

Energy Exchange between Unidirectional Vehicle-To-Grid Aggregators, and Wind and Conventional Generating Companies in the Electricity Market

by

Ahmad Tavakoli

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School of Engineering
University of Tasmania

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Declaration of Originality

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Statement of Co-Authorship

The following people and institution contributed to the publication of work undertaken as part of this thesis:

Name and school: Ahmad Tavakoli, School of Engineering and ICT.

Name and institution: Prof Michael Negnevistky, School of Engineering and ICT, UTAS.

Name and institution: Dr. Kashem Mutaqqi, the University of Wollongong.

Name and institution: Dr. Duy Thanh Nguyen, the TasNetwork Company.

Paper 1, "Energy Exchange between Electric Vehicle Load and Wind Generating Utilities"

Candidate was the primary author and with author 2 (10%), author 3 (5%), and author 4 (5%) contributed to its refinement and development.

Paper 2, "Pool Strategy of a Producer Coordinated with Vehicle-to-Grid Services to Maximize Profitability".

Candidate was the primary author and with author 2 (10%), and author 3 (10%) contributed to its refinement and development.

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Candidate was the primary author and with author 2 (10%), and author 3 (10%) contributed to its refinement and development.

We the undersigned agree with the above stated "proportion of work undertaken" for each of the above published (or submitted) peer-reviewed manuscripts contributing to this thesis.

Signed:

Supervisor's name: Michael Negnevistky
School of Engineering and ICT
University of Tasmania
Date: 26.04.16

Signed:

Head of School
School of Engineering and ICT
University of Tasmania
Date: 26th April 2016

Abstract

The future of humanity is dependent on saving the environment from global warming caused by CO₂ emission from electricity generation and transportation systems. The remedies are the increasing in the penetration of renewable energy in electricity generation and electric vehicles (EVs) in transportation. The main operational problem associated with a high wind penetration and EVs comes from intermittency and unpredictability. The power systems are likely to face increasing uncertainties in both generation and load sides and there is no coordination between them. In addition, EVs might impose excessive load on the grid. Therefore, coordinating the EV aggregator with the generating companies in the electricity market can enhance the stability of the power system via unidirectional vehicle-to-grid (V2G) technology.

This thesis concentrates on the impact of the participation of the EV load aggregator and wind power, and the coordination strategy on the market outcomes and prices.

Firstly, power exchange between the wind generating companies (WGenCos) and EV load aggregators considered as price-takers in the energy and ancillary service markets is modelled and analysed. A two-stage stochastic linear programming-based optimal offering/bidding strategy model is developed for the coordinated EV-Wind units participating in the day-ahead energy, balancing, and regulation markets. In future electricity markets, the EV aggregator will have a more important role with high penetration of EV numbers. Finally, the EV aggregator as price-maker which is in generation portfolio of single and multiple strategic firms including WGenCo and conventional generating companies (CGenCos) is modelled and investigated. A stochastic optimal bidding/offering strategy is developed for the EV load aggregator providing the energy and ancillary services in coordination with single and multiple strategic firms in a pool-based electricity market with endogenous formation of day-ahead and real-time prices, and EV aggregator tariff.

The methodology consists of using stochastic optimization categorized into single and multiple optimization problems. In the single optimization problem, WGenCo and EV aggregator considered as price-takers aim to maximize their objective function associated with equality or inequality constraints. In multiple optimization problems, the strategic firms such as WGenCos, EV aggregators, and other players considered as price-makers, submit supply-offers/demand-bids

to the market operator to participate in the electricity market. A bilevel (hierarchical) model is used in this thesis to model the behaviour of each player. A bilevel problem includes an upper-level problem and a set of lower-level problems which are limited by the upper and lower equality and inequality constraints.

Throughout the thesis, both analytical proofs and numerical examples are provided to review the market analysis of EV aggregator, CGenCo and WGenCo and the coordination strategy.

The numerical results show the effectiveness of the coordination strategy, which is profitable and beneficial with increasing EV penetration in comparison with the incoordination strategy. We conclude that EV aggregators as an individual firm could not compete with other conventional, dispatchable companies. Hence, merging EV aggregators in CGenCos' and WGenCos' portfolio would increase the payoff of EV aggregators and strategic firms. However, a sufficient EV number is a significant factor to affect market and EV aggregator outputs. Moreover, the numerical results show that the EV tariff and numbers at EV-level can influence the market price and power generation at wholesale-level in the electricity market. In addition, the high penetration of EVs leads to increasing the wind power penetration and reducing the wind power curtailment.

Publications

The following is a list of journal and conference papers which have been produced as an outcome of the PhD candidate's research.

1. Tavakoli, M. Negnevitsky, D. T. Nguyen, K. Muttaqi, "Energy Exchange between Electric Vehicle Load and Wind Generating Utilities", IEEE Transactions on Power Systems, vol. 31, no. 2, pp. 1248-1258, March 2016.
2. Tavakoli, M. Negnevitsky, K. Muttaqi, "Pool Strategy of a Producer Coordinated with Vehicle-to-Grid Services to Maximize Profitability", Power Engineering Conference (AUPEC), 2015 Australasian Universities, Wollongong, NSW, 2015, pp. 1-6.
3. Tavakoli, M. Negnevitsky, K. Muttaqi, "A Coordinated Approach to Energy Exchange between Electric Vehicle Load Aggregators and Wind Generation Companies under Uncertainty", 2015 IEEE Power & Energy Society General Meeting, Denver, CO, 2015, pp. 1-5.
4. J. Hamilton, A. Tavakoli, M. Negnevitsky, X. Wang, S. Gamble, "No Load Diesel Application to Maximize Renewable Energy Penetration in Off grid Hybrid Systems" 2016 Paris session, Cigre.
5. A. Tavakoli, Negnevitsky, M., and Kashem, M., "A Decentralized Model Predictive Control for Operation of Multiple Distributed Generators in Islanded Mode", Revised at the IEEE Transactions on Industry Applications.
6. James Hamilton, A. Tavakoli, Michael Negnevitsky, Xiaolin Wang, "Investigation of No Load Diesel Technology in Isolated Power Systems" Accepted at 2016 IEEE Power & Energy Society General Meeting.
7. A. Tavakoli, Negnevitsky, M., Lyden, S. and Haruni A.M.O., "A Decentralized Control Strategy for Multiple Distributed Generation in Islanded Mode", Proceedings of the IEEE/PES General Meeting, Washington DC, USA, 27-31 July, 2014, IEEE Catalog Number CFP14POW-USB.
8. A. Tavakoli, M. Negnevitsky, "A Novel Control Strategy for a Distributed Generation (DG) in Islanding Mode," Published at the AUPEC 2013, 29 September – 3 October 2013.

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List of Symbols

Indices:

b	Battery storage bank
d	Demands.
ev	Electric vehicle fleet.
g	Conventional generating units.
i	Intra-hour (sub-hour) time intervals
j	Firms from 1 to J.
m	A segment of curves
s	Scenarios
t	Hourly time intervals
w	Wind energy units
y	Index for firms from 1 to Y.

Parameters:

C_g	Marginal cost of conventional units (\$/MWh).
$C_{d,t}^L$	Load curtailment cost (\$/MWh).
$D_{ev,s,t,i}$	Energy consumption by EV while driving.
$E_{ev,t}^{max}, E_{ev,t}^{min}$	Max/Min available energy in EV aggregator.
N_{ev}	Number of EV fleet.
$N_{ev,s,t,i}$	Plugged-in EV number scenarios in each fleet
N_I	Number of intrahour intervals.
N_s	Number of scenarios.

N_T	Number of hour intervals.
N_W	Number of wind energy units.
P_g^{max}	Maximum power generation of CGenCo (MW).
P_w^{max}	Maximum power generation of WGenCo (MW).
P_{ev}^{max}	Maximum power drawn of EV aggregator (MW).
$P_{w,t,i}^{RT^s}$	Real-time forecasted wind power (MW).
$P_{b,Max}^{ch}, P_{b,Max}^{dc}$	Max charge/discharge power of the battery storage bank.
$P_{ev,ch}^{max}$	Max charge power of the EV aggregator.
$P_{s,t,i}^{w,f}$	Intra-hour forecasted wind power (MW).
$P_t^{w,f}$	Day-ahead forecasted wind power (MW).
L_d^{max}	Max load demand (MW).
$R_{ev}^{up^{max}}, R_{ev}^{d^{max}}$	Max regulation up/down of EV aggregator (MW).
$R_g^{up^{max}}, R_g^{d^{max}}$	Max regulation up/down of CGenCo (MW).
$SOC_{ev}^{max,min}$	Maximum/Minimum state of the charge.
T	Time at which specified state of charge is adjusted.
$i0, NI$	The beginning and the end of each intra-hour time interval.
$\rho_t^{DA,f}$	Forecasted day-ahead energy price (\$/MWh).
$\rho_{s,t,i}^{RT,f}$	Forecasted real-time energy price (\$/MWh).
ρ_t^{Rup}	Day-ahead regulation-up price (\$/MWh).
ρ_t^{Rdown}	Day-ahead regulation-down price (\$/MWh).
ρ^P	Penalty price (\$/MWh).
$\rho^{T,f}$	Forecasted EV charging tariff (\$/MWh).
$\beta_{d,t}^{DA}$	Day-ahead bid price of LSE (\$/MW)
π_s	Probability of scenarios.
φ_m	Slope of segment in linearized charge /discharge curve.
Δt	Duration of each intra-hour time interval.

Variables:

$a_{s,t,k}^{\Delta}, b_{s,t,k}^{\Delta}$	Auxiliary binary variables.
φ_s, γ	Auxiliary variables for computing CVaR
ρ_t^{DA}	Day-ahead clearing price (\$/MWh).
ρ^T	EV charging tariff (\$/MWh).
$\rho_{t,i,s}^{RT}$	Real-time clearing price (\$/MWh).
$\alpha_{g,t}^{DA}, \alpha_{g,t,i}^{RT^s}$	Day-ahead/Real-time offer price of CGenCos (\$/MW).
$\alpha_{w,t}^{DA}, \alpha_{w,t,i}^{RT^s}$	Day-ahead/Real-time offer price of WGenCos (\$/MW).
$\alpha_{ev,t,i}^{RT^s}$	Real-time offer price of EV aggregator (\$/MW).
$\beta_{ev,t}^{DA}$	Day-ahead bid price of EV aggregator (\$/MW)
$C_{b,s,t,i}^{dc}$	Degradation cost of the discharging battery.
$E_{ev,t,i}^s$	Real-time energy of EV aggregator.
$I_{b,s,t,i}^{ch}$	Charging indicator of the battery storage.
$I_{b,s,t,i}^{dc}$	Discharging indicator of the battery storage.
$I_{ev,t,i}^{up^s}$	Regulation up indicator of the EVs.
$I_{ev,t,i}^{down^s}$	Regulation down indicator of the EVs.
$L_{d,t}^{DA}$	Day-ahead demand (MW).
$L_{d,t,i}^{C^s}$	Demand load curtailment (MW).
PF_s^{CGenCo}	The expected profit of CGenCos (\$).
PF_s^{WGenCo}	The expected profit of WGenCos (\$).
PF_s^{Agg}	The expected profit of EV aggregator (\$).
$P_{g,t}^{DA}$	Day-ahead power generations of CGenCos (MW).
$P_{w,t}^{DA}$	Day-ahead power generations of WGenCos (MW).
$P_{w,t,i}^{C^s}$	Wind power curtailment (MW).
$PoP_{ev,t}$	Preferred operating point (day-ahead power-drawn) of

	the EVs (MW).
$P_{b,s,t,i}^{ch}$	Charge power of the battery storage bank (MW).
$P_{ev,s,t,i}^{ch}$	Real-time power drawn by the EV aggregator (MW).
$P_{b,s,t,i}^{dc}$	Discharge power of the battery storage bank (MW).
$P_{b,m,s,t,i}^{dc}$	Discharge power of the battery storage at segment m (MW).
$P_{s,t,i}^{im}$	Energy imbalance adjusted (provided) by the balancing market (MW).
$P_{ im ,s,t,i}^{im}$	Absolute imbalance power of balancing market
$R_{g,t,i}^{up^s}$	Regulation-up power of CGenCos power (MW).
$R_{g,t,i}^{down^s}$	Regulation-down power of CGenCos power (MW).
$R_{ev,t,i}^{up^s}$	Regulation-up power of EV aggregator power (MW).
$R_{ev,t,i}^{down^s}$	Regulation-down power of EV aggregator power (MW).
$\Delta P_{ \Delta ,s,t,i}^w$	Absolute wind power deviation between Real time and day-ahead scheduling (MW).
$\Delta P_{s,t,i}^w$	Wind power deviation between Real time and day-ahead scheduling (MW).

Dual variables

$\mu_{g,t}^{DA^{max}}, \mu_{g,t}^{DA^{min}}$	Upper/lower bound for day-ahead power generations of CGenCos.
$\mu_{ev,t}^{DA^{max}}, \mu_{ev,t}^{DA^{min}}$	Upper/lower bound for day-ahead POP of EV aggregator.
$\mu_{w,t}^{DA^{max}}, \mu_{w,t}^{DA^{min}}$	Upper/lower bound for day-ahead power generations of WGenCos.
$\mu_{d,t}^{DA^{max}}, \mu_{d,t}^{DA^{min}}$	Upper/lower bound for day-ahead load demand of LSE.
$\mu_{ev,t,i,s}^{up^{max}}, \mu_{ev,t,i,s}^{up^{min}}$	Upper/lower bound for regulation-up power of EV aggregator power.
$\mu_{ev,t,i,s}^{up}$	Upper bound for real-time power of EV aggregator.

$\mu_{ev,t,i,s}^{d^{max}}, \mu_{ev,t,i,s}^{d^{min}}$	Upper/lower bound for regulation-down power of EV aggregator power.
$\mu_{ev,t,i,s}^{down}$	Lower bound for real-time power of EV aggregator.
$\mu_{g,t,i,s}^{up^{max}}, \mu_{g,t,i,s}^{up^{min}}$	Upper/lower bound for regulation-up power of CGenCos power.
$\mu_{g,t,i,s}^{up}$	Upper bound for real-time power of CGenCos.
$\mu_{g,t,i,s}^{d^{max}}, \mu_{g,t,i,s}^{d^{min}}$	Upper/lower bound for regulation-down power of CGenCos power.
$\mu_{g,t,i,s}^{down}$	Lower bound for real-time power of CGenCos.
$\mu_{w,t,i,s}^{c^{max}}, \mu_{w,t,i,s}^{c^{min}}$	Upper/lower bound for wind power curtailment of WGenCos.
$\mu_{d,t,i,s}^{c^{max}}, \mu_{d,t,i,s}^{c^{min}}$	Upper/lower bounds for load demand curtailment of LSE
$\mu_{ev,t}^{EEV^{max}}, \mu_{ev,t}^{EEV^{min}}$	Upper/lower bounds for EV energy constraint of EV aggregator.
$Z\alpha_{g,j}^{DA}$	Dual constraint for day-ahead offer price of CGenCos in the MPEC of firm j.
$Z\alpha_{w,j}^{DA}$	Dual constraint for day-ahead offer price of WGenCos in the MPEC of firm j.
$Z\beta_{ev,j}^{DA}$	Dual constraint for day-ahead bid price of EV aggregator in the MPEC of firm j.
$Z\alpha_{g,j}^{RT^s}$	Dual constraint for real-time offer price of CGenCos in the MPEC of firm j.
$Z\alpha_{w,j}^{RT^s}$	Dual constraint for real-time offer price of WGenCos in the MPEC of firm j.
$Z\alpha_{ev,j}^{RT^s}$	Dual constraint for real-time offer price of EV aggregator in the MPEC of firm j.
$Z_{ev,j}^{DA^{max}}, Z_{ev,j}^{DA^{min}}$	Upper/lower dual constraints for day-ahead POP of EV aggregator in the MPEC of firm j.
$Z_{g,j}^{DA^{max}}, Z_{g,j}^{DA^{min}}$	Upper/lower dual constraints for day-ahead power generations of CGenCos in the MPEC of firm j.

$Z_{w,j}^{DA^{max}}, Z_{w,j}^{DA^{min}}$	Upper/lower dual constraints for day-ahead power generations of WGenCos in the MPEC of firm j.
$Z_{d,j}^{DA^{max}}, Z_{d,j}^{DA^{min}}$	Upper/lower dual constraints for day-ahead load demand of LSE in the MPEC of firm j.
$ZPOP_{ev,j}$	Dual constraint for $POP_{ev,j}$ of EV aggregator in the MPEC of firm j.
$ZP_{g,j}^{DA}$	Dual constraint for $P_{g,j}^{DA}$ of CGenCos in the MPEC of firm j.
$ZP_{w,j}^{DA}$	Dual constraint for $P_{w,j}^{DA}$ of WGenCos in the MPEC of firm j.
$ZL_{d,j}^{DA}$	Dual constraint for $L_{d,j}^{DA}$ of LSE in the MPEC of firm j.
$X_{ev,j}^{DA^{min}}, X_{ev,j}^{DA^{max}}$	Dual constraints for of dual variable $\mu_{ev,t}^{DA^{max}}, \mu_{ev,t}^{DA^{min}}$ of EV aggregator in the MPEC of firm j.
$X_{g,j}^{DA^{min}}, X_{g,j}^{DA^{max}}$	Dual constraints for of dual variable $\mu_{g,t}^{DA^{max}}, \mu_{g,t}^{DA^{min}}$ of CGenCos in the MPEC of firm j.
$X_{w,j}^{DA^{min}}, X_{w,j}^{DA^{max}}$	Dual constraints for of dual variable $\mu_{w,t}^{DA^{max}}, \mu_{w,t}^{DA^{min}}$ of WGenCos in the MPEC of firm j.
$X_{d,j}^{DA^{min}}, X_{d,j}^{DA^{max}}$	Dual constraints for of dual variable $\mu_{d,t}^{DA^{max}}, \mu_{d,t}^{DA^{min}}$ of LSE in the MPEC of firm j.
$Z_{ev,s,j}^{up^{max}}, Z_{ev,s,j}^{up^{min}}$	Upper/lower dual constraints for regulation up of EV aggregator power in the MPEC of firm j.
$Z_{ev,s,j}^{up}$	Upper dual constraint for real-time power of EV aggregator in the MPEC of firm j.
$Z_{ev,s,j}^{d^{max}}, Z_{ev,s,j}^{d^{min}}$	Upper/lower dual constraints for regulation down of EV aggregator power in the MPEC of firm j.
$Z_{ev,s,j}^{down}$	Lower dual constraint for real-time power of EV aggregator in the MPEC of firm j.
$Z_{g,s,j}^{up^{max}}, Z_{g,s,j}^{up^{min}}$	Upper/lower dual constraints for regulation up of CGenCos power in the MPEC of firm j.

$Z_{g,s,j}^{up}$	Upper dual constraints for real-time power of CGenCos.
$Z_{g,s,j}^{d^{max}}, Z_{g,s,j}^{d^{min}}$	Upper/lower dual constraints for regulation down of CGenCos power in the MPEC of firm j.
$Z_{g,s,j}^{down}$	Lower dual constraints for real-time power of CGenCos in the MPEC of firm j.
$Z_{w,s,j}^{c^{max}}, Z_{w,s,j}^{c^{min}}$	Upper/lower dual constraints for wind power curtailment of WGenCos in the MPEC of firm j.
$Z_{d,s,j}^{c^{max}}, Z_{d,s,j}^{c^{min}}$	Upper/lower dual constraints for load demand curtailment of LSE in the MPEC of firm j.
$Z_{ev,s,j}^{EEV^{max}}, Z_{ev,s,j}^{EEV^{min}}$	Upper/lower dual constraints for energy capacity of EV aggregator in the MPEC of firm j.
$ZR_{ev,j}^{up^s}$	Dual constraint for $R_{ev,j}^{up^s}$ of EV aggregator in the MPEC of firm j.
$ZR_{ev,j}^{d^s}$	Dual constraint for $R_{ev,j}^{d^s}$ of EV aggregator in the MPEC of firm j.
$ZR_{g,j}^{up^s}$	Dual constraint for $R_{g,j}^{up^s}$ of CGenCos in the MPEC of firm j.
$ZR_{g,j}^{d^s}$	Dual constraint for $R_{g,j}^{d^s}$ of CGenCos in the MPEC of firm j.
$ZP_{w,j}^{C^s}$	Dual constraint for $P_{w,j}^{C^s}$ of WGenCos in the MPEC of firm j.
$ZL_{d,j}^{C^s}$	Dual constraint for $L_{d,j}^{C^s}$ of LSE in the MPEC of firm j.
$ZE_{ev,j}^{DA}$	Dual constraint for $E_{ev,j}^{DA}$ of EV aggregator in the MPEC of firm j.
$X_{ev,s,j}^{up^{max}}, X_{ev,s,j}^{up^{min}}$	Dual constraints for of dual variable $\mu_{ev,s,j}^{up^{max}}, \mu_{ev,s,j}^{up^{min}}$ of EV aggregator in the MPEC of firm j.
$X_{ev,s,j}^{up}, X_{ev,s,j}^{down}$	Dual constraints for of dual variable $\mu_{ev,s,j}^{up}, \mu_{ev,s,j}^{down}$ of EV aggregator in the MPEC of firm j.

$X_{ev,s,j}^{dmax}, X_{ev,s,j}^{dmin}$	Dual constraints for of dual variable $\mu_{ev,s,j}^{dmax}, \mu_{ev,s,j}^{dmin}$ of EV aggregator in the MPEC of firm j.
$X_{g,s,j}^{upmax}, X_{g,s,j}^{upmin}$	Dual constraints for of dual variable $\mu_{g,s,j}^{upmax}, \mu_{g,s,j}^{upmin}$ of EV aggregator in the MPEC of firm j.
$X_{g,s,j}^{up}, X_{g,s,j}^{down}$	Dual constraints for of dual variable $\mu_{g,s,j}^{up}, \mu_{g,s,j}^{down}$ of EV aggregator in the MPEC of firm j.
$X_{g,s,j}^{dmax}, X_{g,s,j}^{dmin}$	Dual constraints for of dual variable $\mu_{g,s,j}^{dmax}, \mu_{g,s,j}^{dmin}$ of EV aggregator in the MPEC of firm j.
$X_{w,s,j}^{cmax}, X_{w,s,j}^{cmin}$	Dual constraints for of dual variable $\mu_{w,s,j}^{cmax}, \mu_{w,s,j}^{cmin}$ of EV aggregator in the MPEC of firm j.
$X_{d,s,j}^{cmax}, X_{d,s,j}^{cmin}$	Dual constraints for of dual variable $\mu_{d,s,j}^{cmax}, \mu_{d,s,j}^{cmin}$ of EV aggregator in the MPEC of firm j.
$X_{ev,j}^{EEVmax}, X_{ev,j}^{EEVmin}$	Dual constraints for of dual variable $\mu_{ev,j}^{EEVmax}, \mu_{ev,j}^{EEVmin}$ of EV aggregator in the MPEC of firm j.
δ_j^{DA}	Dual constraint of day-ahead energy balance in the MPEC of firm j.
\emptyset_j^{DA}	Strong duality equality for the day-ahead lower-level problem in the MPEC of firm j.
$\delta_{j,s}^{RT}$	Dual constraint of real-time energy balance in the MPEC of firm j.
$\emptyset_{j,s}^{RT}$	Strong duality equality for the real-time lower-level problem in the MPEC of firm j.
δ_j^T	Dual constraint of EV energy balance in the MPEC of firm j.
\emptyset_j^{EV}	Strong duality equality for the EV lower-level problem in the MPEC of firm j.

List of Abbreviations and Acronyms

ARMA	Auto Regressive Moving Average
ARIMA	Auto Regressive Integrated Moving Average
CGenCo	Conventional Generating Company.
DoD	Depth of Discharging
DA	Day-ahead.
DAM	Day-ahead Market.
EPEC	Equilibrium Problem with Equilibrium Constraints.
ESS	Energy Storage System.
EV	Electric Vehicle.
GenCo	Generating Company.
KKT	Karush-Kuhn-Tucker.
LSE	Load Side Entity.
MO	Market Operator.
MILP	Mixed-Integer Linear Programming
MPEC	Mathematical Program with Equilibrium Constraints.
POP	Preferred operating point.
SOC	State of Charge
V2G	Vehicle to Grid.
WGenCo	Wind Generating Company.
RT	Real-time.
RTM	Real-time Market.

Chapter 1

Introduction

1.1 Preface

Electric power generators, transportation systems, and residential houses contribute 41%, 23%, and 6% of the world greenhouse gases, respectively [1]. The strong dependence on foreign energy sources known as “oil addiction”, the growing awareness of global warming impacts of CO₂ emissions, and high energy efficiency are the driving forces for the increase in the penetration of renewable energy and electric vehicles (EVs) [2, 3].

According to the International Energy Agency (IEA), the Electric Vehicles Initiative (EVI) members, with about 63% of the world’s total vehicle demand, plan to consider 83% of EV sales by 2020 [4]. The Global Wind Energy Council has reported that wind power could supply up to 17-19% and 25-30% by 2030, and 2050 of the global electricity supply, respectively [5].

Therefore, power systems are likely to face increasing energy imbalance in both generation and load in the near future. Turning a load on/off or

increasing/decreasing the demand can be effective to balance power in the grid. The coordinated control of the number of EVs (controllable loads) can potentially balance power in the grid [6].

A mechanism is necessary to integrate the electrified transportation within the power system and encourage EV owners as active players in the electricity market [7-8]. Unidirectional vehicle-to-grid (V2G) technology is a mechanism whereby the EV load aggregators in a sizeable number can participate in energy and ancillary services markets due to much faster ramping capability than gas turbines and a cheaper approach than energy storage systems [9-10].

EV aggregators as new market players have to compete with other market players while motivating the consumers to take part in the market. Moreover, the increasing penetration of EVs is another factor that contributes to energy imbalance [11].

Wind generating companies (WGenCos) participate in electricity markets despite their uncertainty to maximize the expected payoff, similarly to the other market producers with consideration of WGenCo as price-maker market players. Both wind generation uncertainty and energy price fluctuations are contributing factors to the decrease of the competitiveness of WGenCos in the energy market [12].

The main operational problem associated with a high wind penetration and EVs comes from intermittency and unpredictability. Also, EVs might impose excessive load on the grid [2]. Therefore, price and the market outcomes are influenced by the participation of the wind power and EV loads in high penetration [13].

This dissertation considers market analysis to investigate the influence of unidirectional V2G and wind power in the future smart grid.

1.2 Review of Current Trends in Integrating Electric Vehicles into Grids

There have been several studies on the integration of EVs into power systems [14-21]. In distribution systems, [22-26] evaluate the impact of EVs charging on the power quality such as voltage profile, harmonic and power losses. In [27-31], optimal scheduling for charging of EV is evaluated. Optimal siting and sizing of EV charging stations are considered in [32-34]. In transmission and generation systems, the benefits of V2G technology to a power system are investigated [35-38].

The first step to use the V2G technology is the economic aspect of EV aggregators. Several studies have also covered the economic aspects of integrating EVs into electricity markets [39-40]. Simulations have shown that EVs acting as smart storage can provide fast and accurate responses for frequency regulation and spinning reserves to aid in the integration of wind and solar power [10]. The definition of V2G is the provision of energy and ancillary services to the electricity grid from EVs [41-43].

EV participation in the energy and ancillary service markets has been investigated in several studies. In [9], the EV participation considered bidirectional V2G interactions. Although V2G can be both unidirectional and bidirectional, the unidirectional V2G is expected to be implemented first as it requires fewer infrastructures and reduces battery degradation by not requiring additional cycling for bidirectional power flow [8]. In [8-9], unidirectional smart charging with EV participation in the energy and regulation markets is studied without considering the stochastic nature of the process.

Stochastic modelling of aggregated EVs and their impact on the optimal load profile of the power system is presented in [9]. However, discharging cost is considered constant and is not affected by depth of discharging (DoD) in these studies.

Currently EV usage is in its initial stage; when EV penetration becomes strong and influences the grid parameters, control of a large number of EVs to balance the entire power system will represent a challenge for power utilities. Several studies have demonstrated the benefits of coordination between wind power generators and EVs in power networks [44-49]. The authors of [50] have examined the effect of EV integration in a wind-thermal power system on emissions produced. In [51], a stochastic unit commitment model is used to simulate wind-thermal power system scheduling with different charging patterns for EVs to reduce the operating costs of a power system. However, these studies did not consider the intra-hour variability of the EV charging behaviour and wind energy generation which limit potential benefits of energy dispatch in the power system. In [52], coordinated wind-EV in three energy dispatching approaches, i.e., valley searching, interruptible and variable rate dispatching, is used without considering economic issues. Study [7] proposed coordinating unidirectional (V2G) services with energy trading. In [7], EV aggregators did not participate in the regulation market. In [53, 39], it has been shown that the highest benefits for EV owners are expected through participation in regulation markets.

There is a lack of a study on the impact of high wind penetration and EVs on the energy and balancing markets equilibria for the coordinated strategy in the literature. However, the limited works study the impact of wind power uncertainty on market equilibria [13]. In [54], an offering strategy for a wind power producer with market power that participates in the day-ahead market as a price-maker and in the balancing market as a deviator is proposed.

Unlike [54], in [55], the producer is a price-taker in the day-ahead market, but a price-maker in the balancing market, and aims at optimizing its expected revenue from these market floors.

In [13], the equilibrium problem in a pool-based two-settlement electricity market is investigated where wind power is included in the generation portfolio of strategic producer in addition to its dispatchable units. Also, in [56], the bidding strategy of the EV aggregator is formulated as a bilevel problem to take into account the EV aggregator to potentially influence market prices without considering the impact of EV tariff and real-time market.

Therefore, in almost all previous studies, the EV aggregators have been considered as price-takers with exogenous formation of EV aggregator tariff. However, with high penetration of EV numbers, EV aggregators will have a more important role in the future electricity market [2].

1.2.1 Common Modelling Assumptions

The main modelling assumptions considered via this dissertation are described in this section.

A. Stochastic Programming Problems

Decision-making problems in the electricity market include imperfect (incomplete) information due to uncertainties in wind speed, energy prices, and the number of EVs [57]. In decision making under uncertainties, stochastic programming is used to make optimal decisions throughout multiple plausible scenarios of each stochastic variable. There are two sets of decision variables in two-stage stochastic programming problems including here-and-now (first stage) and wait-and-see (second stage) decisions. The here-and-now decisions are made before the

realization of the stochastic variables. The wait-and-see decisions are made based on the realized scenarios. Hence, the first stage decisions affect the second stage decisions [7,57-58].

B. Scenario Generation and Reduction Techniques

Appropriate scenario generation and reduction methods are necessary to properly represent the stochastic programming problems. There are several different scenario generation and reduction techniques for stochastic programming [59]. The Monte Carlo simulations are applied to generate scenarios in [59]. In [60], time series models are used to generate scenarios for prices in electricity markets. The most common scenario-reduction technique is based on Kantorovich distance [61]. In [62], a scenario generation and reduction technique for price forecasting is based on the roulette wheel mechanism.

In this dissertation, scenario generation and reduction techniques are used for simulating wind speed, energy price, and the number of EVs engaged as follows.

- Wind and Energy Price Scenarios

Wind speed forecasting for the next day can be obtained from numerical meteorological programs, however, forecasts are never perfect. The Auto Regressive Moving Average (ARMA) model is used to simulate wind speed forecast errors [57, 63-65].

The estimation and adjustment of ARMA models have been investigated in literature. In this thesis, the first order of the ARMA model, ARMA (1,1), is used to simulate wind speed forecasting errors.

Once a large number of scenarios are generated, the wind speed scenarios are transformed into power scenarios through the power conversion curve for each wind turbine [12,65].

Similarly, Auto Regressive Integrated Moving Average (ARIMA) models have been applied to forecast electricity prices, which appear non-stationary when the processes present a periodic or seasonal pattern [57, 65-66]. The details of the methods are described in Appendix A.1.

- EV Penetration Scenarios

The EV availability at each interval has associated unplanned departure and arrival probabilities. The number of EVs is considered to be random, and Monte Carlo simulations are used to generate possible scenarios [9,35,66]. The details of the methods are described in Appendix A.2.

- Scenario Reduction

In stochastic optimization problems with various inherent uncertainties, a large number of scenarios can emerge. It can, therefore, be computationally expensive. Therefore, a technique for reducing the number of scenarios is required.

In this dissertation, the scenario reduction algorithm is based on [67,68]. The basic idea of the scenario reduction is to eliminate scenarios with low-probabilities, and cluster similar scenarios [12,67,68]. The new probability of a preserved scenario is determined as the sum of its initial probability and the probabilities of similar scenarios that have been eliminated. We used SCENRED as a tool for scenario reduction [69]. The details of these methods are described in Appendix A.3.

C. Competition Modelling of the Electricity Market

The electricity market is categorized into two kinds of competition comprising perfect and imperfect competitions [70-71]. In the perfect completion model, the participants are price-takers and their decisions do not affect the market price because of their small potential output. In the imperfect completion model, some strategic players (participants) affect the market price through their decisions. The electricity market most commonly includes a few strategic players as price makers and some (a number of) participants as price takers. Imperfect competition can be modelled using the Cournot model, the Bertrand model, or the Supply Function model.

1. The Bertrand model: In this model, competition among players is in prices [72]. A player offers a price to maximize its profit and the market decides the production quantity [73].
2. The Cournot model: In this model, competition among players is in quantity [72]. A player maximizes its profit by an optimal quantity in the Cournot model, and the other player's quantity is considered to not be changed [73,77-82].
3. The Supply Function model: this model is an extension of both the Bertrand and Cournot models [72]. Each participant submits the supply function offer to the electricity market including quantity and price offers. The Supply Function model is suitable for the pool-based market compared with Cournot, and Bertrand [72,83-85].

In [86], Supply Function models have been applied in the British Electricity Spot Market.

In [87], pure strategy Nash equilibria have been developed when GenCos participate through a supply function by formulating as a mixed-integer linear program (MILP) that does not require any discretising approximations.

In [88], a stepwise supply function model has been used in which a producer submits a set of stepwise price-quantity offers to the market operator (MO).

In [89], the impacts of large-scale integration of intermittent resources (such as wind energy) on electricity market prices using a supply function equilibrium (SFE) model have been studied.

In this dissertation, an SFE model is used in which Conventional Generating Companies (CGenCos), WGenCos, and EV aggregators submit supply-offers/demand-bids to the MO [88].

1.3 Mathematical Structures of Electricity Markets

The combination of regulated (old) and deregulated (new) electricity markets with either perfect or imperfect competition leads to complementarity models. These problem comprise of multiple optimization problems in which primal (power quantities) and dual variables (prices) are constrained together [71].

The mathematical structures of the electricity market can be categorized into single and multiple optimization problems [71].

In a single optimization problem, the WGenCo and EV aggregator as price-takers aim to maximize their objective function associated with equality or inequality constraints as explained in Chapter 3. Fig. 1.1 illustrates the structure of an optimization problem specifying its components.

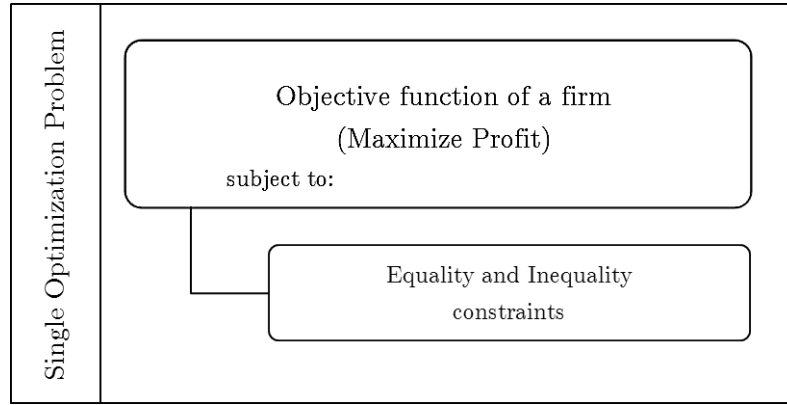


Fig. 1.1 Optimization problem

In multiple optimization problems, the strategic firms such as WGenCos, EV aggregators, and other players as price-maker submit supply-offers/demand-bids to the MO to participate in the electricity market.

A bilevel (hierarchical) model is used in this dissertation to model the behaviour of each player [90-94]. A bilevel problem includes an upper-level problem and a set of lower-level problems which are limited by the upper and lower equality and inequality constraints. The bilevel model can be formulated as a single-level stochastic mathematical program with equilibrium constraints (MPEC) [96]. The lower-level problems are continuous linear and they can be replaced by their Karush-Kuhn-Tucker conditions (KKTs) as shown in Fig. 1.2 [91].

As explained in Chapters 4 and 5, the firm's profit maximization is developed as an upper-level problem, and lower-levels problems represent the market clearing. The MPEC problem is converted into an MILP problem using branch-and-cut algorithms [93].

Multiple MPEC problems constitute an equilibrium problem with equilibrium constraints (EPEC) which are solved through the solutions associated with the strong stationarity conditions (KKTs) of all MPECs as illustrated in Fig. 1.3 [91].

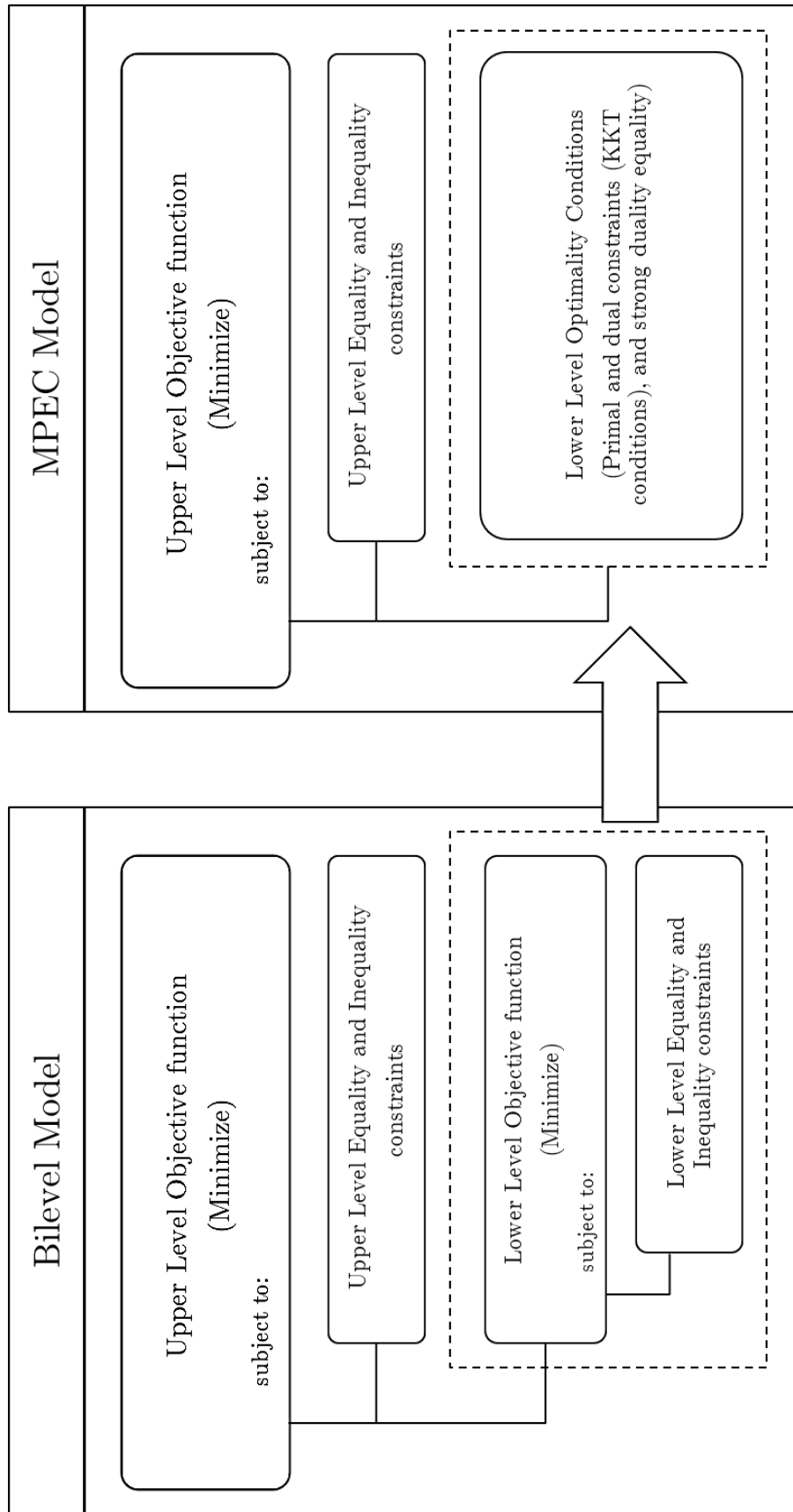


Fig. 1.2 Bilevel model formulated as a single-level stochastic MPEC

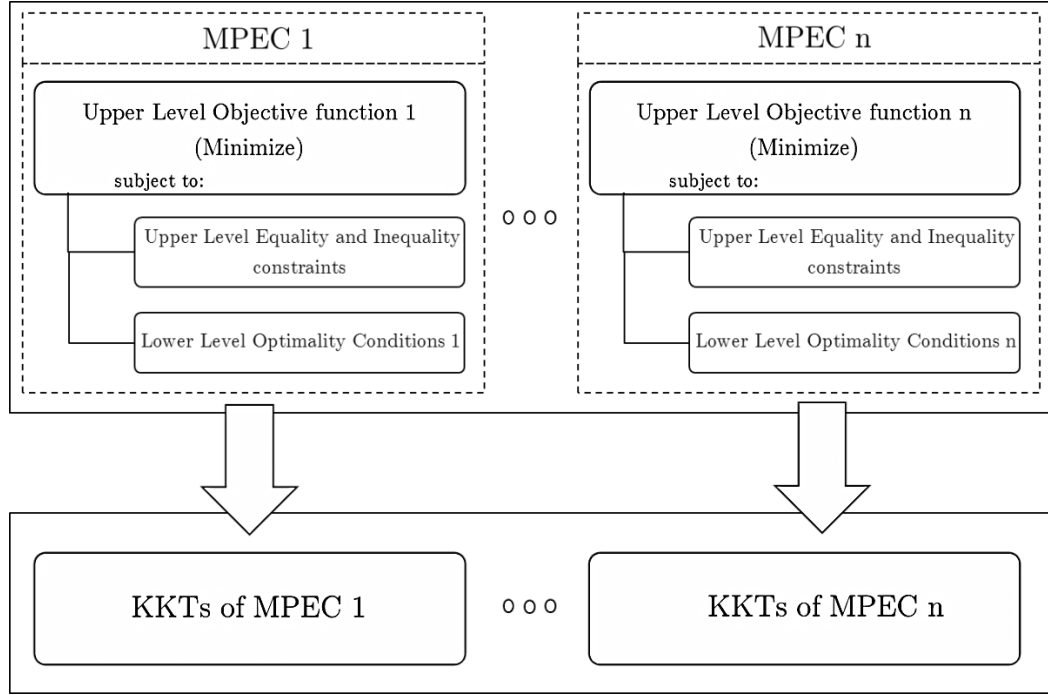


Fig. 1.3 An Equilibrium Problem with Equilibrium Constraints (EPEC)

1.4 Project Objectives

This thesis focuses on revaluating the electricity market associated with the new players such as the EV load aggregator, and analysing the impact of coordination strategy on the market outcomes and prices. The coordination occurs between the EV load aggregator and generating companies through V2G technology.

In this document, we investigate the two studies as follows:

- Development of a power exchange between the EV load aggregators and WGenCos considered as price-takers in the energy and ancillary service markets.
- Development of a power exchange between the EV load aggregators and all generating companies considered as price-makers in the single and multiple firms.

1.5 Thesis Organization

The dissertation's organization is as follows:

Chapter 1 provides an introduction consisting of preface, the literature review, the modelling assumptions, the mathematical structures of electricity markets, and the thesis organization and objectives.

Chapter 2 provides a review of EVs in electricity markets. Firstly, divers electricity markets and their time framework are explained. The role of demand dispatch in regulation ancillary services is explained. Finally, the role of the EV aggregator in regulation ancillary service and energy markets and their mathematical formulation are represented.

Chapter 3 presents an approach to energy exchange between electric vehicle (EV) load and wind generation utilities participating in the day-ahead energy, balancing, and regulation markets. An optimal bidding/offering strategy model is developed to mitigate wind energy and EV imbalance threats, and optimize EV charging profiles. A new strategy model is based on optimizing decision making of a WGenCo in selecting the best option among the use of the balancing or regulation services, the use of the energy storage system (ESS) and the use of all of them to compensate wind power deviation. Energy imbalance is discussed using conventional systems, ESS, and EV-Wind coordination; results are compared and analysed. Stochastic intra-hour optimization is solved by MILP. Uncertainties associated with wind forecasting, energy price, and behavior of EV owners based on their driving patterns, are considered in the proposed stochastic method, and validated through several case studies.

Chapter 4 proposes an approach to investigate the impact of merging EV load aggregators into the portfolio of a strategic firm, and the influence of this strategy on electricity market equilibrium and EV tariff for the sake of increasing a firm's profit while retaining social welfare and optimizing EV charging profiles. A strategic firm trades electric energy in an electricity pool including the day-ahead (DA) and real-time (RT) markets at wholesale-level while EV owners connect to an EV aggregator in order to take part in the market at EV-level. A stochastic intra-hour bilevel model is developed, which includes a) the firm's profit maximization as an upper-level problem and b) DA and RT social welfare, and the EV owner battery energy maximizations with the corresponding endogenous price formation as the lower-level problems. The problem is formulated from an MPEC to a MILP. Uncertainties of wind speed, and behavior of EV owners based on their driving patterns are considered in the proposed strategy, and validated through several case studies.

Chapter 5 proposes a methodology to describe market equilibria in a pool-based electricity market, where each CGenCo, WGenCo and EV aggregator is defined in multiple strategic firms. A bilevel model for each strategic firm is developed including expected payoff as upper-level problem, and several lower-level problems represent the market clearing. Each bilevel model is converted into a single-level MPEC by replacing the lower-level problems with their primal-dual optimality conditions. An EPEC is formulated to consider all single firms' MPECs. The optimality conditions of the EPEC are derived by replacing each MPEC with its KKT conditions. The optimality conditions of the EPEC are linearized by formulating and solving an MILP problem. A case study is discussed to validate the proposed model to recognize meaningful market equilibria, where the strategic CGenCo, WGenCo and EV aggregator participate in energy and

1.5 Thesis Organization

ancillary services. We compare different cases including coordination and incoordination strategies, with and without EVs, the impact of different EV numbers, and different combination of units in multiple firms.

Chapter 6 concludes this thesis, providing the major contributions of the thesis and suggests some directions for future work targeting to develop the research studies presented here.

Appendix A provides mathematical background and details regarding the scenario generation and reduction techniques for simulating wind speed, energy price, and the number of EVs engaged.

Appendix B provides the mathematical background of formulating absolute values of variables as a MILP.

Appendix C contains additional data from Chapter 5 which are not directly relevant to the discussions of Chapter 5, but they represent additional details and complements.

Chapter 2

Electric Vehicles in Electricity Markets

2.1 Introduction

This chapter provides an overview of EVs in electricity markets. The concept of V2G and the role of EV aggregators in regulation ancillary service and energy markets and their mathematical formulation are represented.

The rest of the chapter is organized as follows. Section 2.2 provides a general description of the different electricity markets and their time framework, and the roles of the market players. Section 2.3 provides some insight into the uncertainty in power systems. Section 2.4 explains the demand dispatch in regulation ancillary services. Section 2.5 explains further the concept of unidirectional and bidirectional V2G and EV aggregators. Finally, Sections 2.6 and 2.7 present the regulation ancillary services via unidirectional V2G and their mathematical formulation in electricity market.

2.2 Electricity Markets

Electricity markets are multi-commodity markets. The different energies (products) and services are traded in the different power marketplaces. The products include the base energy, reserves, regulation, and balancing energy which are altered in control method, response time, duration of the power dispatch, contract terms, and price [71]. These energy and services are traded in the marketplaces such as pool, reserve and regulation, bilateral, and future markets [39]. In this dissertation, the participants in the electricity markets are load-side entities (LSE), CGenCos, load aggregators, and WGenCos described as follows.

1. The LSE: provide the electrical demand and energy requirements to the end-use customers that cannot participate directly in the electricity markets.
2. CGenCos: supply and sell the electricity energy generated by fossil fuels or nuclear energy in the electricity market. Dispatchable CGenCos (such as natural gas and coal plants) may participate in the reserve and regulation markets to provide reserve power and load following capacity, respectively.
3. Load Aggregator: purchases the electricity to supply energy to sizable special clients (such as EV owners) through bilateral contracts in the futures market. The clients connect to the load aggregator in order to take part in the market indirectly. The Load aggregator determines its energy capacity and tariff for customers based on achieved market data.
4. WGenCos: are non-dispatchable producers generating electricity energy by wind power. A WGenCo must participate in the balancing market to compensate its deviations from the scheduled generation because of inherent intermittency of wind energy.

2.2.1 Pool-based Electricity Market

A pool-based electricity market typically includes the day-ahead market and real-time (balancing) market trading on a short-term basis [57].

In the day-ahead market, producers and consumers submit respectively supply-offers and demand-bids to the MO to participate in the electricity market. The MO runs the day-ahead market clearing process to determine day-ahead price and energy quantities schedules [65].

In the real-time market, producers and consumers submit balancing offers to the MO to participate in the electricity market. The balancing (real-time) market is cleared based on achieved day-ahead market data to balance the excess and deficit of production and consumption. Fig. 2.1 shows the structure of a pool-based electricity market [57].

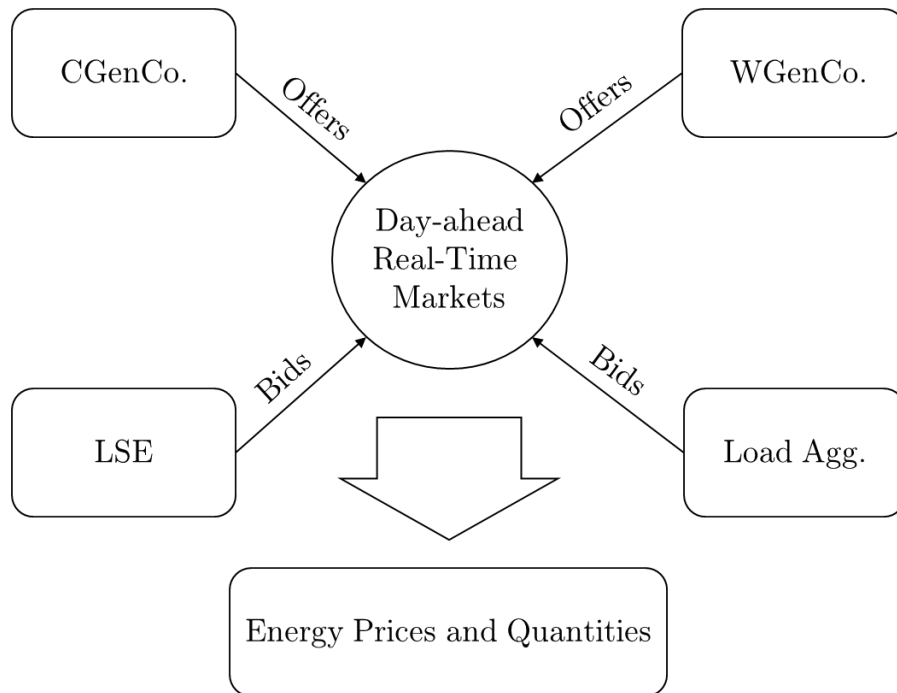


Fig. 2.1 The structure of a pool-based electricity market

The time framework for the day-ahead market is the whole day (d), which is cleared at 10 AM of the day (d-1). The balancing market ensures the real-time balance between generation and demand by offsetting the difference between the real-time operation and the last energy program cleared in the market. For this reason, this market remains open until 10 minutes before the delivery hour [65].

2.2.2 Reserve and Regulation Markets

The reserve is an important product to ensure the secure system operation and energy delivery in the huge fluctuations of the intermittent energy generation and demand. The reserve market supplies standby power (spinning and non-spinning) which is cleared in the day-ahead market [39,57].

The regulation market provides up and down real-time regulation capacities to match generation and load demand (load-following). The amount of regulation capacity contracted is the total amount by which power can deviate from a baseline level [39,57]. The baseline is often called the preferred operating point (POP) [6]. It represents the average level of operation for a market participant providing regulation services [9].

Participants submit supply-offers for regulation capacity (or POP) to the market operator which is cleared in the day-ahead market. In the real time market, the power generation capacities might be increased or decreased from a baseline level called “regulation up” and “regulation down”, respectively [53].

The regulation up and down are never provided at the same time, although a producer can contract to provide one of them or both over the same contract period [57].

2.2.3 The Futures Market and Bilateral Contracts

The futures market is an auction market in which participants buy and sell physical or financial products to trade on a medium- or long-term horizon [57].

A bilateral contract is a free agreement arranged outside an organized marketplace between a generating company (GenCo) and a load aggregator, or a load aggregator and some customer (such as EVs) shown in Fig. 2.2.

Fig. 2.3 shows the clearing times of future, day-ahead, reserve, regulation, and balancing (real-time) markets.

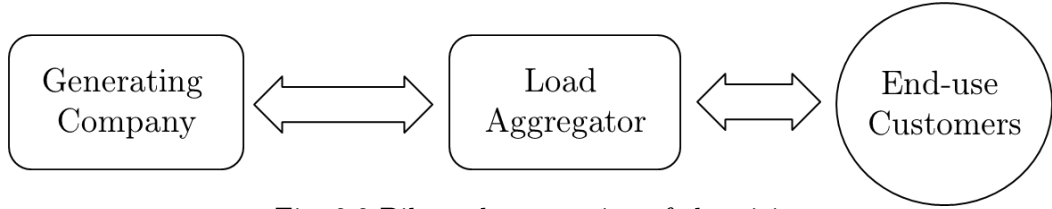


Fig. 2.2 Bilateral contracting of electricity

2.3 Uncertainty in the Power Grid

To maintain network frequency as close to the nominal value (50 or 60 Hz) as possible, a real-time balance of generation and load have to be operated. Any deviation between load and generation is compensated by adding or subtracting power. In other words, generation is controlled to follow load [39].

With high penetration of renewable generation such as solar and wind energy, the load-following strategy faces new challenges. Wind and solar energy generation are highly unpredictable and quickly changeable. The more conventional generation capacities (such as coal and natural gas plants) are required to provide the ancillary services and fast ramping for the load-following with increases in intermittent renewable energy sources [6].

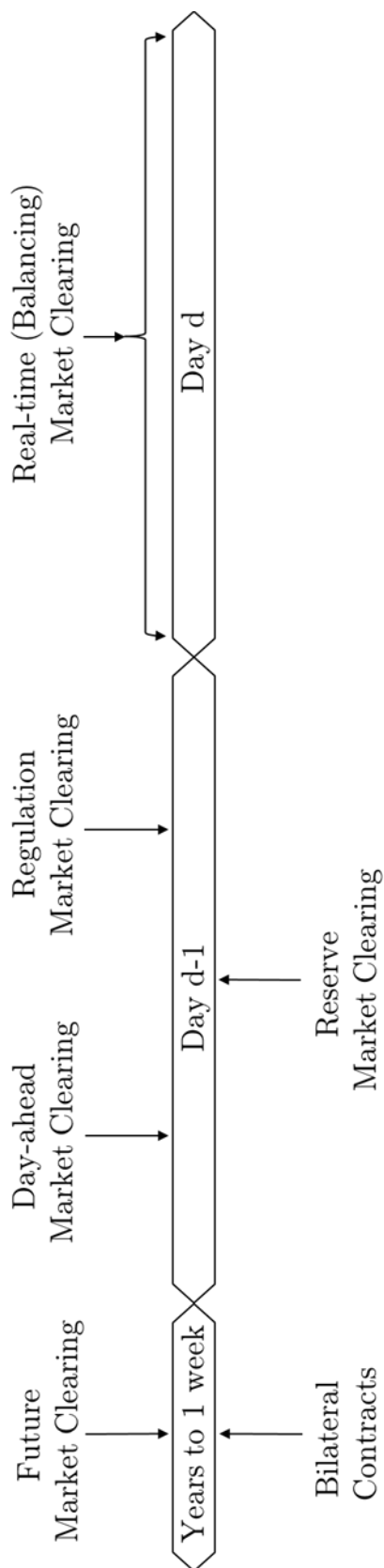


Fig. 2.3 The clearing times of future, day-ahead, reserve, regulation, and balancing (real-time) markets

A approach is introduced as a direct control of some loads [6]. Turning a load on/off or increasing/decreasing the demand can be effective to balance power in the grid. Therefore, without adding new dispatchable generation capacity, we can compensate the imbalanced energy in the network via the dispatchable loads under demand dispatch [9].

2.4 Demand Dispatch

Demand dispatch (DD) is, in some sense, similar to demand response (DR) with the main difference that DR is used only to shed loads at peak times, while DD is intended to be used actively at all times [6]. Demand dispatch is a generalization of the term DR.

The application of DD could provide regulation ancillary services to balance load and generation on the grid in the different time scale from hours to seconds. However, conventional generators can ramp up and down for load-following strategy. Conventional generators respond slowly and need to deal with higher emissions, lower efficiency, and limited ramp rates. Energy storage such as flywheel and batteries could be used for regulation ancillary services, but they cause high cost and complexity on the power system [6,43,53].

Some kinds of load called dispatchable loads turn on/off repeatedly and become generation-following under DD. Turning some loads on/off such as lights would cause discomfort for the electricity consumer. However, remotely controlled loads are unnoticeable such as electric hot water heaters, dishwashers, washers, dryers and charging an electric vehicle at night.

The criteria of a dispatchable load are [6]:

- 1) predictable to be forecasted for next day,
- 2) switchable to turn on/off frequently,

- 3) flexible to draw power in the specific time and energy amount.

According to the criteria mentioned above, one of the best candidates for demand dispatch would be electric vehicle loads through unidirectional V2G technology [8,41].

2.5 Vehicle-to-Grid (V2G)

The concept of V2G is that EVs connect to the grid while parked. V2G application can be both unidirectional and bidirectional. In bidirectional V2G, EVs charge from the grid during low load periods and discharge to the grid when power is low [43]. In unidirectional V2G, the EV battery is considered as a dispatchable load to balance energy in the grid. V2G is expected to be implemented first as it requires less infrastructure and reduces the battery degradation by not requiring additional cycling for bidirectional power flow [9].

V2G requires a connection system to the grid, communication system, and control and metering systems. The control signals can be transmitted through a cell phone and Internet networks [39].

The battery of an individual EV is too small to affect the grid. An EV aggregator including large numbers of EVs acts as an intermediary between individual EVs and the MO. EVs can connect to a third-party aggregator individually or as a fleet operator (a parking lot) within a city or whole area [43]. An EV aggregator can decrease the volume of communication signals to the MO. Therefore, the EV aggregators can reduce the market operator complexity and improve the cyber-security [11].

2.6 Regulation Ancillary Services via Unidirectional V2G

The EVs, when aggregated in a sizeable number, can play an important role in regulation service due to much faster ramping capability than gas turbines through V2G technology [6,41,42].

The EV aggregator participates as dispatchable load in the energy and ancillary service markets by submitting energy bids and regulation offers. POP represents the average level of operation for a market participant providing regulation services. It is assumed that the EV aggregator can deviate from the day-ahead power-drawn (or POP) to amend imbalance energy by reducing or increasing their charging rate with consideration of EV aggregator energy constraints [6,53].

Fig. 2.4 illustrates EV aggregator regulating while POP value is determined for one hour in the day-ahead market and regulation-up or -down dispatch deviates from POP following generation in the real-time market. Regulation-down and regulation-up dispatches represent increasing and decreasing the EV load demand, respectively.

2.7 Mathematical Formulation of Unidirectional V2G in the Electricity Market

A stochastic objective function (2.1) is to maximize the profits of the EV aggregator. According to the method discussed above, the EV aggregator's revenue is obtained by selling ancillary services, as well as selling energy to its clients at the tariff (ρ^T). The aggregator encourages EV owners to join in by offering an attractive price for charging in comparison with petrol and energy prices.

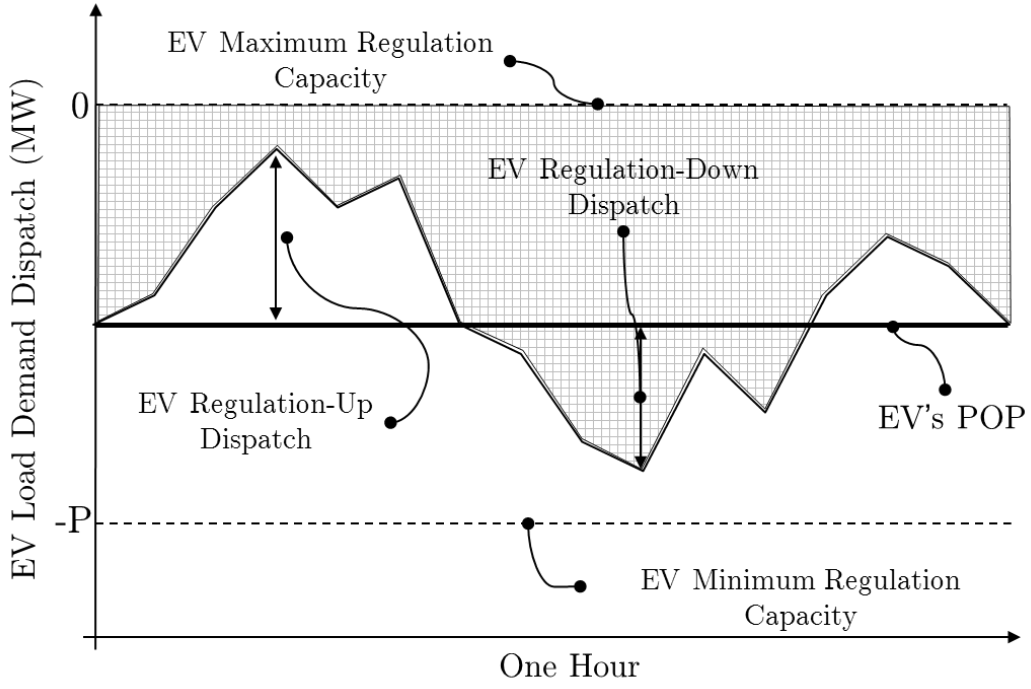


Fig. 2.4 EV aggregator regulating; the shaded area highlights the energy drawn from the grid

The EV aggregator's cost is associated with buying energy at the day-ahead market price (ρ_t^{DA}) for regulation capacity (or POP). In this strategy, the power deviation between day-ahead and real-time markets is compensated by regulating the charging power down ($R_{ev,t,i}^{down^s}$) or up ($R_{ev,t,i}^{up^s}$) of POP at the real-time market price ($\rho_{s,t,i}^{RT}$). Hence, the EV aggregator's payoff is represented as:

$$\begin{aligned} \text{Max } \left\{ \sum_{t=1}^{N_T} \sum_{ev=1}^{N_{ev}} \rho^T - \rho_t^{DA} \text{POP}_{ev,t} \right\} \\ + \pi_s \cdot \left[\frac{1}{N_I} \sum_{t=1}^{N_T} \sum_{ev=1}^{N_{ev}} \sum_{i=1}^{N_I} [\rho_{s,t,i}^{RT} - \rho^T] (R_{ev,t,i}^{up^s} - R_{ev,t,i}^{down^s}) \right] \end{aligned} \quad (2.1)$$

Constraints for the EV's POP, capacity to increase the charging rate for regulation down ($R_{ev,t,i}^{down^s}$), capacity to decrease the charging rate for regulation up ($R_{ev,t,i}^{up^s}$) are given in (2.2)-(2.6).

$$PoP_{ev,t} \leq P_{ev,ch}^{max} \cdot N_{ev,s,t,i} \quad (2.2)$$

$$PoP_{ev,t} + R_{ev,t,i}^{down^s} \leq P_{ev,ch}^{max} \cdot N_{ev,s,t,i} \quad (2.3)$$

$$R_{ev,t,i}^{up^s} \leq PoP_{ev,t} \quad (2.4)$$

$$R_{ev,t,i}^{down^s} \leq P_{ev,ch}^{max} \cdot N_{ev,s,t,i} \cdot I_{ev,t,i}^{down^s} \quad (2.5)$$

$$R_{ev,t,i}^{up^s} \leq P_{ev,ch}^{max} \cdot N_{EV,s,t,i} \cdot I_{ev,t,i}^{up^s} \quad (2.6)$$

Since the regulation up and down are never provided at the same time, the status of regulation down or up is determined in (2.7).

$$I_{ev,t,i}^{down^s} + I_{ev,t,i}^{up^s} \leq 1 \quad (2.7)$$

The energy balance equation for the EV aggregator is given in (2.8). The EV energy capacity in each intra-hour ($E_{ev,t,i}^s$) is the EV energy capacity in prior intra-hour ($E_{ev,t,i-1}^s$) plus energy charged by drawing power from the grid ($P_{ev,s,t,i}^{ch} \cdot \Delta t$) minus energy consumed by EVs while driving. The regulation capacity of the EV aggregator increases when the numbers of charging EVs increase and, vice versa as given in (2.8).

$$E_{ev,t,i}^s = E_{ev,t,i-1}^s + P_{ev,s,t,i}^{ch} \cdot \Delta t - (1 - N_{ev,s,t,i}) D_{ev,s,t,i} \quad (2.8)$$

The energy capacity of EV aggregator is constrained in (2.9).

$$\begin{aligned}
E_{ev,t}^{min} \cdot N_{ev,s,t,i} \cdot SOC_{ev}^{min} &\leq E_{ev,s,t,i} \\
&\leq E_{ev,t}^{max} \cdot N_{ev,s,t,i} \cdot SOC_{ev}^{max}
\end{aligned} \tag{2.9}$$

The constraint (2.10) imposes limits at the beginning and at the end of each interval of the energy capacity of the EV aggregator.

$$E_{ev,t,i0}^s = E_{ev,t-1,NI}^s \tag{2.10}$$

The constraint (2.11) specifies the level of State of Charge (SOC) to be reached by time (T) for a specified EV client. This constraint is an option for clients to set up the desirable SOC for their EVs at the time of expected commuting (T).

$$E_{ev,T,i}^s = E_{ev,t}^{max} \cdot N_{ev,s,t,i} \cdot SOC_{ev}^{max} \tag{2.11}$$

Chapter 3

Energy Exchange between Electric Vehicle Load and Wind Generating Utilities

3.1 Introduction

An electricity market, e.g. PJM, may have a two-settlement system consisting of two markets: a day-ahead market (DAM) and a real-time balancing market. Generators are paid for any generation that exceeds their day-ahead scheduled quantities and are penalized for generation deviations below their scheduled quantities [6]. Whenever the scheduled day-ahead wind power generation deviates from the real-time market (RTM), the profitability of WGenCos decreases due to imbalance energy charges for the wind units [6, 35].

To mitigate potential wind energy imbalance charges for WGenCos, the authors in [35], suggested a coordinated scheduling of wind energy units and storage units. However, the study was based on pumped storage power systems which represent only around 2.2% of the total generation with efficiency at about 75%; they have high installation costs, and are limited to specific locations [10]. Although stored energy increases the economic value of wind energy [8], the use of large scale battery-based ESS is currently still prohibitively expensive.

The imbalanced energy exchange based on a dedicated coordination between EV load aggregators and WGenCos can potentially increase the competitiveness of WGenCos and EV-load customers in the energy market.

This chapter develops an optimal bidding/offering strategy for EV load demands in coordination with a WGenCo, thereby maximizing the WGenCo's competitiveness, optimizing EV charging profiles and mitigating imbalance energy provided by the balancing market. The EV aggregator participates in the energy and ancillary service markets while the WGenCo participates in the day-ahead energy and balancing markets.

The main contributions of the chapter are as follows [97-98]:

- The development of a two-stage stochastic linear programming (SLP)-based optimal offering/bidding strategy model for the coordinated EV-Wind units participating in the day-ahead energy, balancing, and regulation markets.
- The development of an SLP-based optimal offering strategy model for the ESS-Wind units participating in the day-ahead energy, and balancing markets.

- A new strategy model based on optimal decision making for selecting between the balancing, regulation services, and/or using ESS for a WGenCo to compensate wind power deviation.
- Comprehensive comparisons of three different cases comprising conventional systems (WGenCo without energy storage), WGenCo with ESS, and a coordinated EV-Wind energy exchange for dealing with energy imbalance.
- Consideration of the uncertainties associated with wind forecast, energy price, and EV owners' behaviour based on driving patterns.

The rest of this chapter is organized as follows. Section 3.2 discusses the market framework for the sake of conventional systems (WGenCo without storage), WGenCo with the energy storage system, and a power system with a coordinated EV-Wind energy exchange. Section 3.3 presents the mathematical model formulations of proposed models. Several case studies are discussed in Section 3.4. Finally, Section 3.5 concludes, summarizing the chapter.

3.2 Market Framework

The day-ahead market and a real-time balancing market are the two settlement systems considered in this chapter. Participants in the DAM submit supply-offers/demand-bids to the system operator. These participants also submit supply-offers for the regulation capacity, and they may later submit revised regulation quantities, which are different from day-ahead offer quantities, without any penalty imposed [53].

Wind generation and EV load aggregators participate as price takers in the DAM by hourly offering/bidding amounts that are based on the day-ahead

forecast while energy and price variations occur within minutes (i.e. intra-hour) [35].

In this chapter, three different strategies are considered to deal with the energy imbalance for a WGenCo participating in short-term electricity markets (DAM and balancing). In the subsections below, these strategies are demonstrated using conventional systems (WGenCo without storage), WGenCo with the energy storage system, and a power system with a coordinated EV-Wind energy exchange.

3.2.1 Conventional Systems

WGenCos participate in the DAM and balancing market. The imbalance charge is imposed on the WGenCo to balance energy in the power system due to deviation of the RTM [12, 35]. The WGenCo's payoff in this method is as follows:

$$\begin{aligned} \rho_t^{DA} P_{w,t}^{DA} - \rho^P P_{w,t}^{DA} - P_{w,t,i}^{RTS} - \rho_{s,t,i}^{RT} (P_{w,t}^{DA} \\ - P_{w,t,i}^{RTS}) \end{aligned} \quad (3.1)$$

According to (3.2), the wind energy deviation between day- ahead and real-time is considered as the energy imbalance:

$$\Delta P_{s,t,i}^w = P_{w,t}^{DA} - P_{w,t,i}^{RTS} = P_{s,t,i}^{im} \quad (3.2)$$

3.2.2 WGenCo with the Energy Storage System

It is assumed that battery storage belongs to the WGenCo participating in the DAM and balancing market. The authors in [12] and [35] proposed a scheduling strategy for the coordination of wind and storage units without any flexibility for the WGenCo to adapt when the storage units fail.

This section proposes a new scheduling strategy, which considers optimal decision making for WGenCos in selecting between the balancing market and ESS to compensate for wind power deviations. The WGenCo can decide whether to use the ESS or not based on penalties, energy prices, maintenance requirements and other factors. According to (3.3), the wind energy deviation between the DAM and RTM can be compensated by the battery storage system and balancing market. The optimization determines the one which is the most efficient.

$$\Delta P_{s,t,i}^w = P_{w,t}^{DA} - P_{w,t,i}^{RTS} = (P_{b,s,t,i}^{dc} - P_{b,s,t,i}^{ch}) + P_{s,t,i}^{im} \quad (3.3)$$

A degradation cost from the battery bank charging/discharging is considered in this method. The WGenCo's payoff is as follows:

$$\rho_t^{DA} P_{w,t}^{DA} - \rho^P P_{s,t,i}^{im} - \rho_{s,t,i}^{RT} (P_{s,t,i}^{im}) - C_{b,s,t,i}^{dc} \quad (3.4)$$

3.2.3 Coordinated EV-Wind Energy Exchange

In the method discussed above, the WGenCo participates in the short-term electricity market. The EV aggregator participates as dispatchable load in the energy and ancillary service markets by submitting energy bids and regulation offers. The amount of regulation contracted is the total amount by which power can deviate from a baseline level. The baseline is often called the POP (Preferred operating point) [6]. The term POP itself comes from ancillary services markets. It represents the average level of operation for a market participant providing regulation services [8]. It is assumed that the EV aggregator can deviate from the day-ahead power-drawn (or POP) to amend wind imbalance energy by reducing or increasing their charging rate with consideration of EV aggregator energy

constraints. Therefore, the offer price in the day-ahead market does not change in the real-time market while offer quantities can be revised [17].

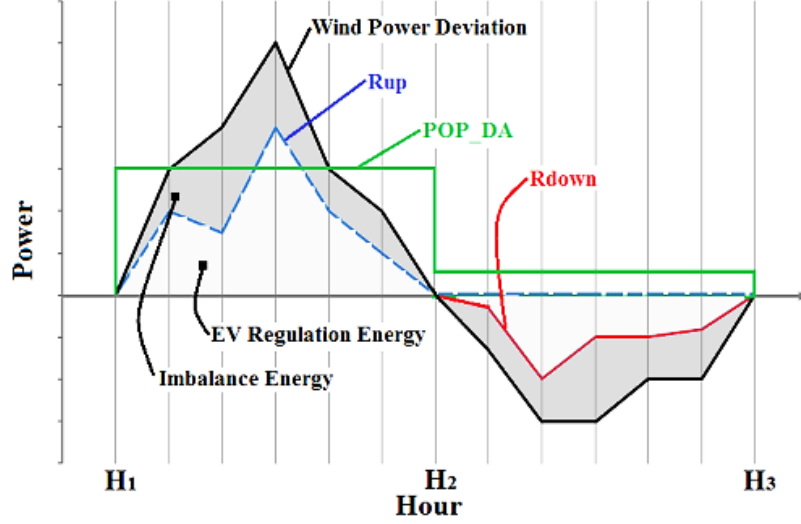


Fig. 3.1 Coordination between EV demand and wind power deviation in energy and regulation market.

The penalties are not imposed for revising the day-ahead power drawn offer quantities [39]. When real-time wind energy exceeds the forecasted day-ahead wind energy, the EV aggregator regulates down with more charging, and vice versa (see Fig. 3.1).

The wind energy deviation between DAM and RTM is compensated by structured regulation, which is provided by the EV aggregator, and unstructured regulation, which is provided by the balancing market as follows:

$$\Delta P_{s,t,i}^w = P_{w,t}^{DA} - P_{w,t,i}^{RTS} = (R_{ev,t,i}^{up^s} - R_{ev,t,i}^{down^s}) + P_{s,t,i}^{im} \quad (3.5)$$

Therefore, the WGenCo can select between regulation and balancing markets based on penalties, energy prices, lack of EVs, and other factors. The WGenCo's payoff in coordination with EV aggregators in this part is:

$$\begin{aligned} \rho_t^{DA} P_{w,t}^{DA} - \rho^P P_{s,t,i}^{im} - \rho_{s,t,i}^{RT} \Delta P_{s,t,i}^w - (\rho_t^{Rup} R_{ev,t,i}^{ups} \\ + \rho_t^{Rdown} R_{ev,t,i}^{downs}) \end{aligned} \quad (3.6)$$

Real-time power drawn by the EV aggregator is given by:

$$P_{s,ev,t,i}^{ch} = PoP_{ev,t} - R_{ev,t,i}^{ups} + R_{ev,t,i}^{downs} \quad (3.7)$$

Hence, the EV aggregator's revenue is obtained by selling ancillary services, as well as selling energy to its clients at a fixed price (ρ^T). In this chapter, the tariff charged to EV clients is assumed to be constant (fixed). The aggregator encourages EV owners to join in by offering an attractive price for charging in comparison with petrol and energy prices.

The EV aggregator's cost is associated with buying energy for EV charging.

Hence, the EV aggregator's payoff is represented as:

$$\begin{aligned} -(\rho_t^{DA} - \rho^T) PoP_{ev,t} + [\rho_{s,t,i}^{RT} - \rho^T] (PoP_{ev,t} - P_{s,ev,t,i}^{ch}) \\ + (\rho_t^{Rup} R_{ev,t,i}^{ups} + \rho_t^{Rdown} R_{ev,t,i}^{downs}) \end{aligned} \quad (3.8)$$

3.3 Mathematical Model Formulation

In this section, the problems of optimal dispatch for three different WGenCo scheduling strategies are formulated and presented. These problems are solved as a two-stage mixed-integer stochastic program [54]. The first-stage variable is decided before stochastic variables with the hourly day-ahead input parameters such as $\rho_t^{DA,f}$, ρ_t^{Rup} , and ρ_t^{Rdown} . The second-stage variable is dependent on

scenarios with sub-hourly (intra-hourly) RT input parameters such as $\rho_{s,t,i}^{RT,f}$, $N_{ev,s,t,i}$, and $P_{s,t,i}^{w,f}$.

3.3.1 Conventional Systems

The objective function

$$\begin{aligned}
 & \left\langle \text{Max} \sum_{s=1}^{N_s} \pi_s \left[\sum_{t=1}^{N_T} \sum_{w=1}^{N_w} \rho_t^{DA,f} P_{w,t}^{DA} \right] \right. \\
 & - \pi_s \cdot \left[\frac{1}{N_I} \sum_{i=1}^{N_I} \sum_{t=1}^{N_T} \sum_{w=1}^{N_w} \rho_{s,t,i}^{RT,f} \Delta P_{s,t,i}^w \right] \\
 & \left. - \pi_s \cdot \left[\frac{1}{N_I} \sum_{i=1}^{N_I} \sum_{t=1}^{N_T} \sum_{w=1}^{N_w} \rho^P \Delta P_{|\Delta|s,t,i}^w \right] \right\rangle
 \end{aligned} \tag{3.9}$$

is to maximize the revenue from selling the day-ahead wind energy minus the cost of energy imbalance [12], [35]. The intra-hour based wind power deviation between real-time and day-ahead schedules is

$$\Delta P_{s,t,i}^w = P_{w,t}^{DA} - P_{w,t,i}^{RT^s} = P_{s,t,i}^{im} \tag{3.10}$$

and generation limits are given in

$$P_{w,t,i}^{RT^s} \leq P_{s,t,i}^{w,f} \tag{3.11}$$

$$P_{w,t}^{DA} \leq P_t^{w,f} \tag{3.12}$$

The following equations are a linear representation of the absolute value of variable $\Delta P_{s,t,i}^w$ for the MILP formulation [12]:

$$\Delta P_{|\Delta|s,t,i}^w - \Delta P_{s,t,i}^w \geq 0 \quad (3.13)$$

$$\Delta P_{|\Delta|s,t,i}^w + \Delta P_{s,t,i}^w \geq 0 \quad (3.14)$$

$$\Delta P_{|\Delta|s,t,i}^w - \Delta P_{s,t,i}^w \leq M a_{s,t,i}^\Delta \quad (3.15)$$

$$\Delta P_{|\Delta|s,t,i}^w + \Delta P_{s,t,i}^w \leq M [1 - a_{s,t,i}^\Delta] \quad (3.16)$$

In (3.15), M is the upper bound of $(\Delta P_{|\Delta|s,t,i}^w - \Delta P_{s,t,i}^w)$, and in (3.16), M is the upper bound of $(\Delta P_{|\Delta|s,t,i}^w + \Delta P_{s,t,i}^w)$. These equations are proved in Appendix C.

3.3.2 WGenCo with the Energy Storage System

The objective function

$$\begin{aligned} & \left\langle Max \sum_{s=1}^{N_s} \pi_s \cdot \left[\sum_{t=1}^{N_T} \sum_{w=1}^{N_w} \rho_t^{DA,f} P_{w,t}^{DA} \right] \right. \\ & - \pi_s \cdot \left[\frac{1}{N_I} \sum_{i=1}^{N_I} \sum_{t=1}^{N_T} \sum_{w=1}^{N_w} \rho_{s,t,i}^{RT,f} \cdot P_{s,t,i}^{im} \right] \\ & - \pi_s \cdot \left[\frac{1}{N_I} \sum_{i=1}^{N_I} \sum_{t=1}^{N_T} \sum_{w=1}^{N_w} \rho^P P_{|im|,s,t,i}^{im} \right] \\ & \left. - \pi_s \cdot \left[\frac{1}{N_I} \sum_{i=1}^{N_I} \sum_{t=1}^{N_T} C_{b,s,t,i}^{dc} \right] \right\rangle \end{aligned} \quad (3.17)$$

is to maximize the revenue from selling the day-ahead wind energy minus the cost of energy imbalance and battery charging/discharging costs [39]. The intra-hour-based wind power deviation between real-time and day-ahead schedule is given in

$$\Delta P_{s,t,i}^w = P_{s,t,i}^{im} + P_{b,s,t,i}^{dc} - P_{b,s,t,i}^{ch} \quad (3.18)$$

The wind power deviation has two terms including imbalance, and battery charging/discharging energy. The following equations are a linear form of the absolute value of variable $P_{s,t,i}^{im}$ for MILP formulation:

$$P_{|im|,s,t,i}^{im} - P_{s,t,i}^{im} \geq 0 \quad (3.19)$$

$$P_{|im|,s,t,i}^{im} + P_{s,t,i}^{im} \geq 0 \quad (3.20)$$

$$P_{|im|,s,t,i}^{im} - P_{s,t,i}^{im} \leq M b_{s,t,i}^\Delta \quad (3.21)$$

$$P_{|im|,s,t,i}^{im} + P_{s,t,i}^{im} \leq M [1 - b_{s,t,i}^\Delta] \quad (3.22)$$

where M is a large positive number [12]. Battery charging/discharging and imbalance power constraints are in

$$P_{|im|,s,t,i}^{im} \leq \Delta P_{|\Delta|,s,t,i}^w \quad (3.23)$$

$$0 \leq P_{b,s,t,i}^{dc} \leq P_{b,Max}^{dc} I_{b,s,t,i}^{dc} \quad (3.24)$$

$$0 \leq P_{b,s,t,i}^{ch} \leq P_{b,Max}^{ch} I_{b,s,t,i}^{ch} \quad (3.25)$$

$$I_{s,b,t,i}^{dc} + I_{s,b,t,i}^{ch} \leq 1 \quad (3.26)$$

Constraints presented in (3.11)-(3.16) are used as well.

The charging/discharging cost depends directly on the depth of discharge (DoD) and the number of cycles to failure of the battery [39]. As the depth of aggregated battery discharge increases, the number of cycles to failure decreases.

The piecewise linear representation of the concave discharge cost curve of EV batteries in the proposed MIP formulation is shown in

$$C_{b,s,t,i}^{dc} = P_m^{min} \cdot I_{b,s,t,i}^{dc} + \sum_{m=1}^{N_M} \varphi_m \cdot P_{b,m,s,t,i}^{dc} \quad (3.27)$$

$$\sum_{m=1}^{N_M} P_{b,m,s,t,i}^{dc} + P_m^{min} I_{b,s,t,i}^{dc} = P_{EV,s,t,i}^{dc} \quad (3.28)$$

3.3.3 Coordinated EV-Wind Energy Exchange

The objective function

$$\begin{aligned} & \left\langle \text{Max} \sum_{s=1}^{N_s} \pi_s \cdot \left[\sum_{t=1}^{N_T} \sum_{w=1}^{N_w} \rho_t^{DA,f} P_{w,t}^{DA} \right] \right. \\ & - \pi_s \cdot \left[\sum_{t=1}^{N_T} \sum_{EV=1}^{N_{EV}} (\rho_t^{DA,f} - \rho^{T,f}) P_o P_{ev,t} \right] \\ & + \pi_s \cdot \left[\frac{1}{N_I} \sum_{t=1}^{N_T} \sum_{EV=1}^{N_{EV}} \sum_{i=1}^{N_I} [\rho_{s,t,i}^{RT,f} - \rho^{T,f}] (R_{ev,t,i}^{up^s} - R_{ev,t,i}^{down^s}) \right] \\ & - \pi_s \cdot \left[\frac{1}{N_I} \sum_{i=1}^{N_I} \sum_{t=1}^{N_T} \sum_{w=1}^{N_w} \rho_{s,t,i}^{RT,f} \cdot \Delta P_{s,t,i}^w \right] \\ & \left. - \pi_s \cdot \left[\frac{1}{N_I} \sum_{i=1}^{N_I} \sum_{t=1}^{N_T} \sum_{w=1}^{N_w} \rho^P \cdot P_{|im|,s,t,i}^{im} \right] \right\rangle \quad (3.29) \end{aligned}$$

is to maximize the profits of the EV aggregator and the WGenCo according to (3.6) and (3.8). In this strategy, the wind power deviation between DAM and RTM is compensated by regulating the down/up charging power of the EV

aggregator ($R_{ev,t,i}^{down^s}/R_{ev,s,t,i}^{UP}$) and by the energy imbalance ($P_{s,t,i}^{im}$) provided by the grid, as given by

$$\Delta P_{s,t,i}^w = P_{s,t,i}^{im} + R_{ev,t,i}^{up^s} - R_{ev,t,i}^{down^s} \quad (3.30)$$

The energy balance equation for the EV aggregator is given in

$$E_{ev,t,i}^s = E_{ev,t-1,i}^s + P_{ev,s,t,i}^{ch} \cdot \Delta t - (1 - N_{ev,s,t,i}) D_{ev,s,t,i} \quad (3.31)$$

The EV energy capacity in each intra-hour ($E_{ev,t,i}^s$) is the EV energy capacity in the prior intra-hour ($E_{ev,t,i-1}^s$) plus energy charged by drawing power from the grid ($P_{ev,s,t,i}^{ch} \cdot \Delta t$) minus energy consumed by EVs while driving. The regulation capacity of the EV aggregator increases when the numbers of charging EVs increase and, vice versa as given in (3.31).

Constraints presented in (3.11)-(3.16) and (3.19)-(3.23) are also used here. Constraints for the EV's POP, capacity to increase the charging rate for regulation down ($R_{ev,t,i}^{down^s}$), capacity to decrease the charging rate for regulation up ($R_{ev,t,i}^{up^s}$) are given in

$$PoP_{ev,t} \leq P_{ev,ch}^{max} \cdot N_{ev,s,t,i} \quad (3.32)$$

$$PoP_{ev,t} + R_{ev,t,i}^{down^s} \leq P_{ev,ch}^{max} \cdot N_{ev,s,t,i} \quad (3.33)$$

$$R_{ev,t,i}^{up^s} \leq PoP_{ev,t} \quad (3.34)$$

$$R_{ev,t,i}^{down^s} \leq P_{ev,ch}^{max} \cdot N_{ev,s,t,i} \cdot I_{ev,t,i}^{down^s} \quad (3.35)$$

$$R_{ev,t,i}^{up^s} \leq P_{ev,ch}^{max} \cdot N_{EV,s,t,i} \cdot I_{ev,t,i}^{up^s} \quad (3.36)$$

In

$$I_{ev,t,i}^{down^s} + I_{ev,t,i}^{up^s} \leq 1 \quad (3.37)$$

the status of regulation down or up is determined. The EV energy constraint is presented in

$$\begin{aligned} E_{ev,t}^{min} \cdot N_{ev,s,t,i} \cdot SOC_{ev}^{min} &\leq E_{EV,s,t,i} \\ &\leq E_{ev,t}^{max} \cdot N_{ev,s,t,i} \cdot SOC_{ev}^{max} \end{aligned} \quad (3.38)$$

The constraint

$$E_{ev,t,i0}^s = E_{ev,t-1,NI}^s \quad (3.39)$$

imposes limits at the beginning and at the end of each interval of the energy capacity of the EV aggregator. The constraint

$$E_{ev,T,i}^s = E_{ev,t}^{max} \cdot N_{ev,s,t,i} \cdot SOC_{ev}^{max} \quad (3.40)$$

specifies the level of SOC to be reached by time (T) for a specified EV client. This constraint is an option for clients to set up the desirable SOC for their EVs at the time of expected commuting (T). For example, the EV client wants to have the battery fully charged (i.e., 100% SOC) by the departure time (for example, 5:00pm) to go back home.

3.4 Case Studies and Numerical Results

To test the proposed model, a WGenCo with a single wind farm is assumed to participate in a day-ahead energy market. The capacity of the wind farm is 200 MW, which is a relatively small farm compared to the wholesale energy market. The WGenCo is a price-taker; it is not a dominant player in the wholesale energy market. 10,000 scenarios are reduced to just ten using scenario reduction techniques presented in [69]. Fig. 3.2 shows the intra-hourly wind power generation forecasted for these ten scenarios. Fig. 3.3 shows the day-ahead energy price, regulation up/down prices, and intra-hour real time energy price scenarios. Fig. 3.4 shows the intra-hourly EV penetration forecasted for the same ten scenarios. We consider the worst conditions to occur when peak demand and high regulation prices coincide with the lowest penetration of EVs (see Figs. 3.3—3.4. The number of intra-hour intervals is 6 (10 min each).

The maximum EV charging power is assumed to be 7.3 kW, and the energy capacity of each EV is 27.4 kWh. Average annual driving distance of an EV is assumed 20,000 km with an average daily distance of 52.91 km. The required energy for an EV is 9 kWh/day with an average of 5.87 km/kWh [35], [39], [43]. In this chapter, the fixed charging tariff is assumed to be \$0.01/kWh [12]. We assume that the required energy for driving in one direction is the same as that of returning to the starting point. For the EV aggregator, we consider two EV penetration scenarios 1,000 and 10,000 EVs. The cycle efficiency is 83.6% for a charging/discharging efficiency of 95% [35, 65]. The EV fleet has its own commute time based on the region, city, traffic patterns, etc. The number of EV fleets is assumed to be one with commute intervals between 7 A.M and 9 A.M, and between 5 P.M. and 8 P.M. However, the equations provided in the chapter are

general and can be used for any number of EV fleets. In this chapter, 100% SOC is considered for departure times to represent the worst case scenario.

The capacity of a battery bank of the ESS is assumed to be similar to the capacity of 10,000 EVs. The current price of a complete battery pack is \$600/kWh.

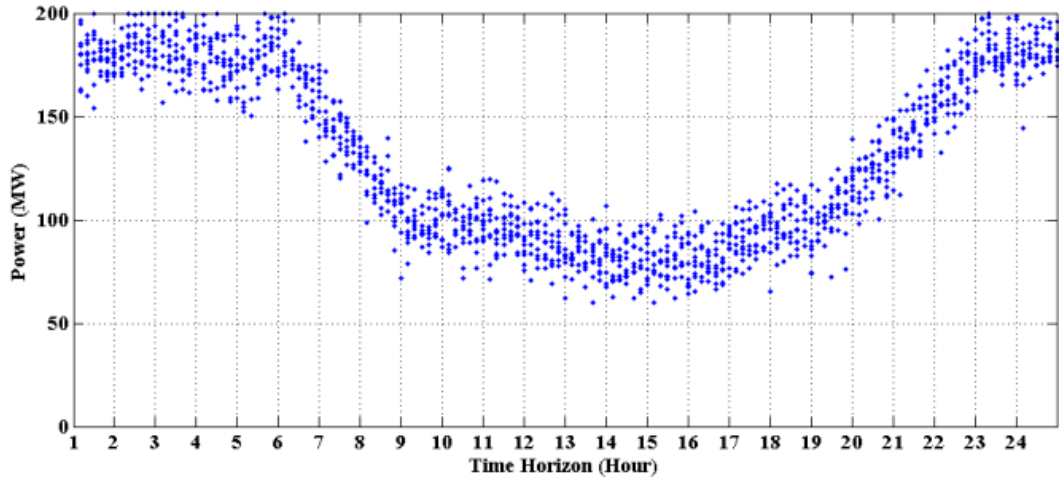


Fig. 3.2 The intra-hourly wind power generation forecasted for ten scenarios.

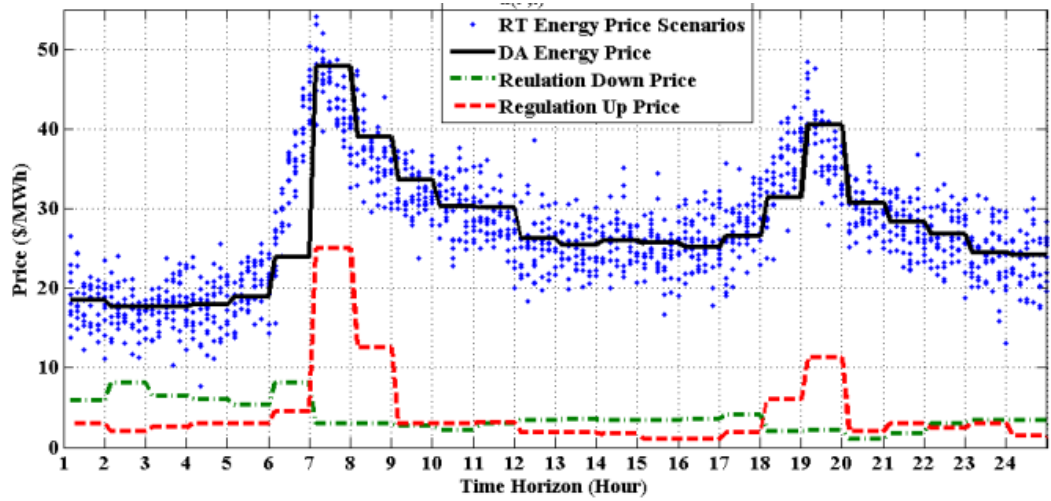


Fig. 3.3 The day-ahead energy price, regulation up/down prices, and intra-hour real time energy price scenarios.

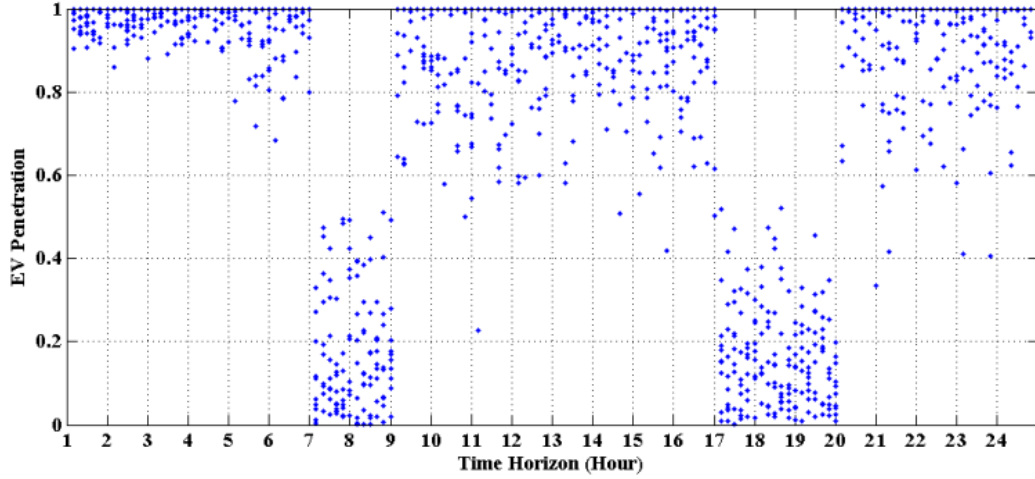


Fig. 3.4 The intra-hourly EV penetration forecasted for ten scenarios.

Four cases are considered for the investigation of two important issues: the payoff, and generation and demand dispatch. The four cases are defined as follows:

- Case A—Conventional systems: The WGenCo without ESS participates in the energy market.
- Case B—ESS-wind: The WGenCo with ESS participates in the energy market.
- Case C—1K-EV-Wind: The WGenCo in coordination with 1,000 EVs participates in the energy and regulation markets.
- Case D—10K-EV-Wind: The WGenCo in coordination with 10,000 EVs participates in the energy and regulation markets.

3.4.1 Payoff Analysis

Table 3.1 shows the total WGenCo's payoffs for all cases when the penalty price is \$30/MWh. The total payoff for Case D is \$79,888.98, while the expected payoffs in cases A and B are \$77,023.94 and \$77,064.63, respectively. The

difference between the two payoffs in case D and case A is \$2,869.04 (3.72%), while the difference between the two payoffs in Case B and Case A is just \$40.69 (0.05%). It is clear that using the battery storage at a penalty price of \$30/MWh is not affordable. The EV penetration impact on the payoffs is obvious when comparing cases C and D. Table 3.1 shows that the payoff in Case D exceeds that of Case C by 1.86%.

Table 3.1
WGenCo's Payoffs In Different Cases at the \$30 Penalty Price

Cases	Case A	Case B	Case C	Case D
DA Energy Sale Revenue (\$)	81132.56	81177.86	83395.12	99763.90
DA Revenue Adjustment (\$)	-875.06	-702.45	-2307.46	-17520
Imbalance Charge (\$)	-3233.56	-3071.77	-2491.57	-589.20
Regulation Cost (\$)	-	-	-195.60	-1620.61
Discharging Cost (\$)	-	-339.01	-	-
Payoff (\$)	77023.94	77064.63	78400.48	79888.98

Tables 3.2—3.5 and Figs. 3.5—3.7 show the impact of the penalty price on the WGenCo's payoffs for different cases. It is clear that with the increasing penalty price, the day-ahead energy sale revenue and the total payoff decrease with more conservative day-ahead generation offers. However, with the EV-wind coordination, the total payoff with respect to the penalty price remains almost constant (see Fig. 3.5). For example, while penalty price changes from \$10/MWh to \$150/MWh, the total payoff in cases D, C, B, and A decreases by 2.21%, 7.42%, 8.02% and 10.01%, respectively. It is clear that the total payoff under variable penalty price is more sustainable (stable) with the 10K-EV-Wind coordination (see Fig. 3.5).

Comparing results presented in Tables 3.2—3.4 shows that the difference between the two payoffs in Case D and Case A at the penalty price of \$10/MWh is \$384 (0.4%), while this difference is \$6683 (8.4%) at the penalty price of \$150/MWh. Therefore, the effectiveness of coordinating EVs with wind generation becomes more apparent for penalty prices greater than \$20/MWh (see Fig. 3.5).

Comparing Case B with cases C and A shows that the total payoff in Case B is greater than in Case A for penalty prices greater than \$40/MWh. The total payoff in Case B is lower than in Case C although they get closer with higher penalty prices (see Fig. 3.5), since the battery discharging cost is more affordable under higher penalty prices.

Comparing cases D and C shows that the appropriate capacity of the EV aggregator is an important factor in coordinating the EVs and WGenCos. Benefits of the use of EV aggregators of sufficient capacity include higher total payoffs, lower imbalance charges and less conservative day-ahead generation offers. However, a smaller number of EVs offer better results in comparison with cases A and B.

Fig. 3.6 shows imbalance charges provided by the balancing market versus penalty prices. It is clear that the imbalance charge in Case D is less than in the other cases. Fig. 3.7 demonstrates that an increase in penalty price decreases the EV regulation cost for the WGenCO (or the EV regulation profitability for the EV aggregator) when wind deviations decrease, thus the EV regulation contribution is lower. The battery charging/discharging cost for Case B would increase with the increase in the penalty price, because imbalance charges imposed by the balancing market are more expensive than the battery charging/discharging cost under higher penalty prices; thus the ESS contribution is higher.

Table 3.2

Impact of the Penalty Price on WGenCo's Payoffs In Case A

Penalty Price (\$/MWh)	10	50	100	150
DA Energy Sale Revenue (\$)	78966.02	79304.49	76935.06	75953.17
DA Revenue Adjustment (\$)	4853.88	-1375.28	-720.16	-545.94
Imbalance Charge (\$)	-3136.93	-2332.88	-2411.29	-2745.66
Payoff (\$)	80682.97	75596.32	73803.61	72661.56

Table 3.3

Impact of the Penalty Price on WGenCo's Payoffs In Case B

Penalty Price (\$/MWh)	10	50	100	150
DA Energy Sale Revenue (\$)	78721.16	79605.04	79097.86	77505.53
DA Revenue Adjustment (\$)	4046.73	-1018.64	-272.77	-149.45
Imbalance Charge (\$)	-2330.48	-1763.76	-939.59	-920.54
Discharging Cost (\$)	-1.49	-987.91	-3272.19	-2254.82
Payoff (\$)	80435.92	75834.72	75907.64	74329.83

Table 3.4

Impact of the Penalty Price on WGenCo's Payoffs In Case D

Penalty Price (\$/MWh)	10	50	100	150
DA Energy Sale Revenue (\$)	103290.28	98285.83	96980.28	96154.44
DA Revenue Adjustment (\$)	-21730	-16370	-15380	-14760
Imbalance Charge (\$)	-492.93	-492.99	-486.48	-560.03
Regulation Cost (\$)	-2339.87	-1650.21	-1543.62	-1489.86
Payoff (\$)	81067.35	79775.13	79568.18	79344.94

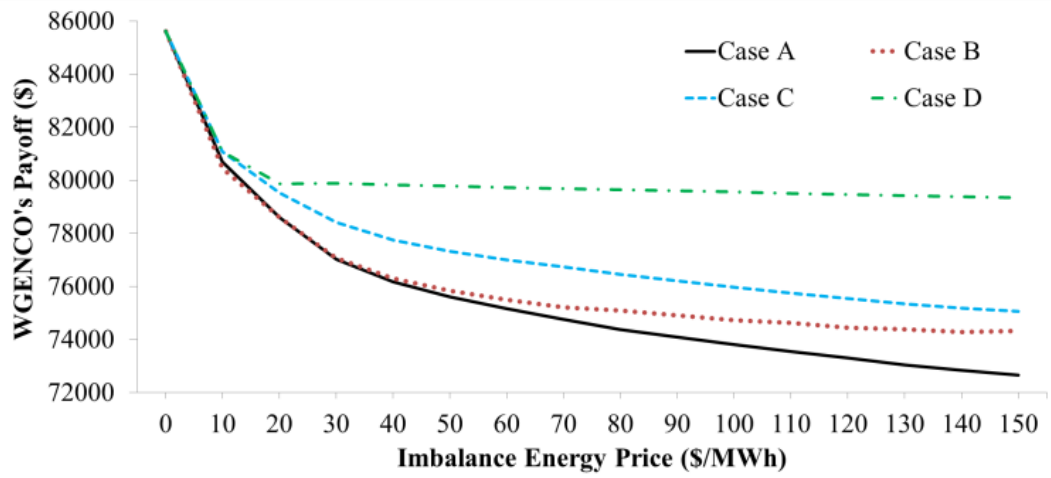


Fig. 3.5 The WGenCo's payoff versus penalty prices.

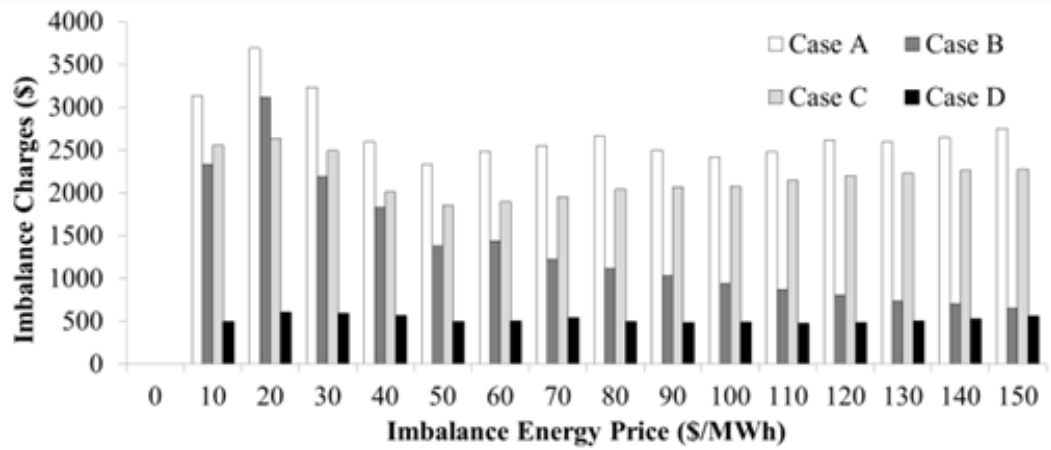


Fig. 3.6 Imbalance charges provided by balancing market versus penalty prices

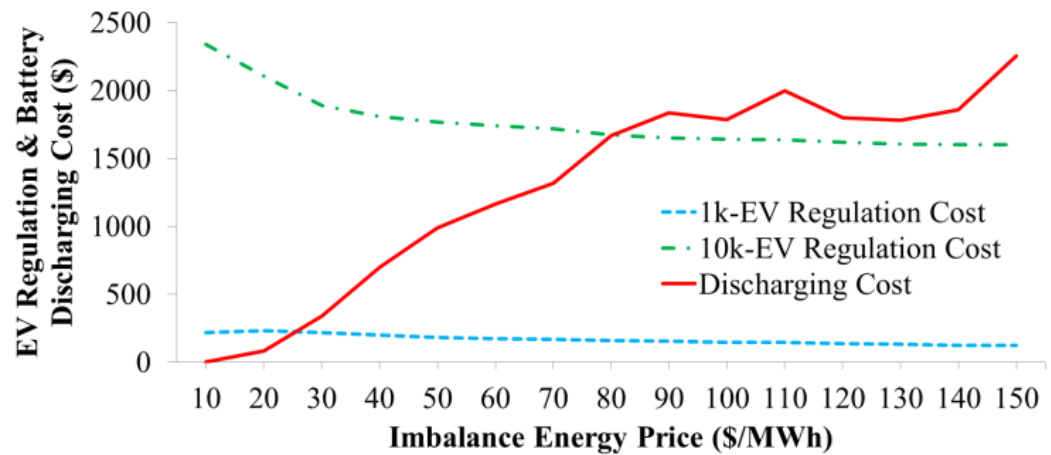


Fig. 3.7 EV regulation and battery discharging cost versus penalty prices.

3.4.2 Demand and Generation Dispatch analysis

Wind power generation and EV load demand dispatch in Case D at penalty prices of \$10/MWh and \$150/MWh are shown in Figs. 3.8—3.9, respectively. These figures show day-ahead wind power (Pw-DA), real-time wind power (Pw-RT), wind power deviation (ΔPw), day-ahead EV charging schedule (POP-DA), EV regulation up/down, and energy imbalance provided by the balancing market (P^{im}). Figs. 3.10 and 3.11 show wind power generation and battery bank dispatch in Case B at penalty prices of \$10/MWh and \$150/MWh, respectively.

It can be seen that the Pw-RT schedules in Figs. 3.8, 3.9, and 3.10 look very similar, but the schedule in Fig. 3.11 differs noticeably. This demonstrates that the penalty price increase has a greater impact in Case B than in Case D. For instance, in Table 3.5, the total Pw-RT per day in cases B and D are 2,977 MWh, and 3,111 MWh, respectively, at the penalty price of \$150/MWh. However, the total Pw-RT per day in cases B and D are the same for the \$10/MWh penalty price. This demonstrates that the effectiveness of the coordinated EV-wind energy exchange becomes more apparent when penalty prices are higher. From Table 3.5, it can also be observed that the total Pw-RT in Case D remains almost unchanged irrespective of the penalty price.

If we now compare the total ΔPw per day for all cases under the \$10/MWh penalty price, we find that this parameter is much higher in Case D (this can be attributed to the less conservative day-ahead generation offers). We can also find that the total P^{im} per day under any penalty price is smaller in Case D than in all other cases (this fact is particularly apparent under the \$10/MWh penalty price).

Results presented in Figs. 3.8, 3.9 and Table 3.5 also demonstrate that the increase in the penalty price decreases the total up/down EV regulation contributions – the total up/down EV regulation at \$10/MWh and \$150/MWh penalty prices are 761.9 MWh and 584.1 MWh, respectively.

Results presented in Figs. 3.10, 3.11 and Table 3.5 show that the increase in penalty price leads to higher battery charging/discharging costs (Case B). The total charging/discharging costs at penalty prices of \$10/MWh and \$150/MWh are 4.7 MWh and 69.8 MWh, respectively. Battery discharge power increases under the higher penalty prices, because the battery charging/discharging cost is more affordable than imbalance charges imposed by the balancing market under higher penalty prices.

Table 3.5
Total Real-Time Wind Power Generation,
Wind Power Deviation and Energy Imbalance per Day

Total (MWh)	Penalty Price	Case A	Case B	Case C	Case D
Pw-RT		3138	3138	3138	3137
ΔP_w	10 (\$/MWh)	313.69	216.56	325.12	811.24
P^{im}		313.69	211.86	255.42	49.29
Pw-RT		2896	2990	2976	3116
ΔP_w	100 (\$/MWh)	24.11	79.16	60.58	609.2
P^{im}		24.11	9.39	20.74	4.86
Pw-RT		2867	2977	2949	3111
ΔP_w	150 (\$/MWh)	18.30	73.59	46.1	588.8
P^{im}		18.30	4.317	15.167	3.733

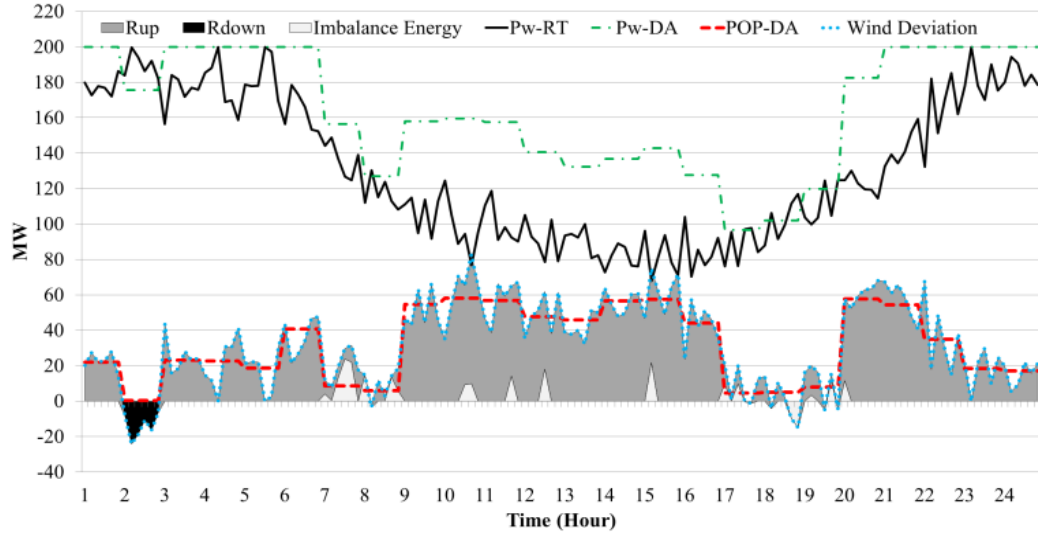


Fig. 3.8 Wind power generation and EV demand schedule in Case D under the \$10/MWh penalty price.

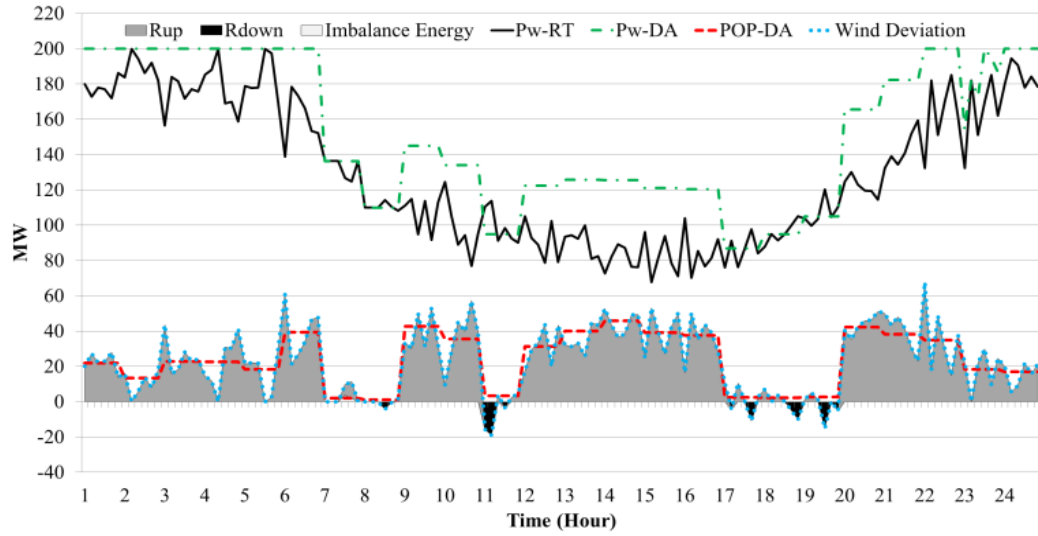


Fig. 3.9 Wind power generation and EV demand schedule in Case D under the \$150/MWh penalty price.

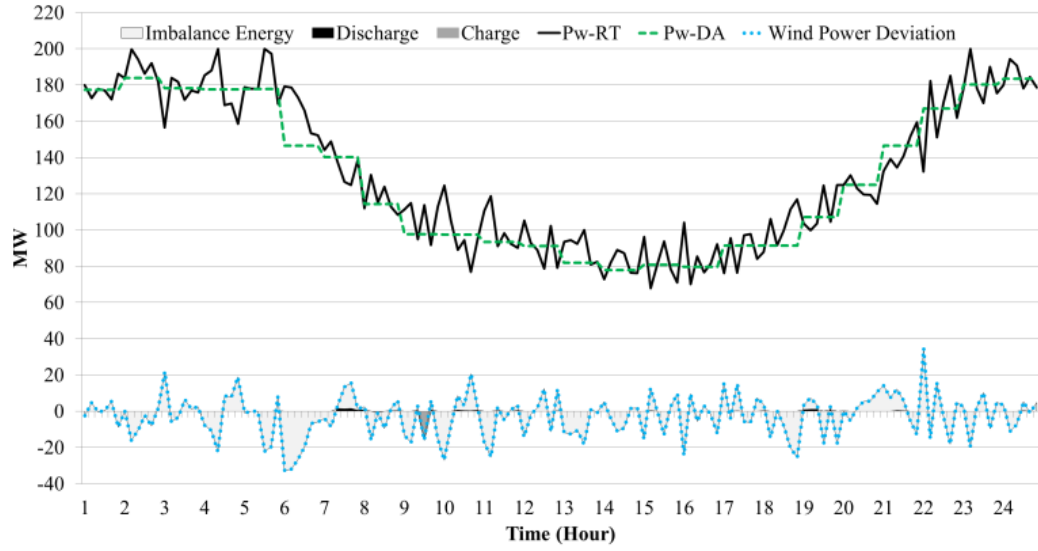


Fig. 3.10 Wind power deviation and battery energy storage profile in case B at 10 \$/MWh penalty price

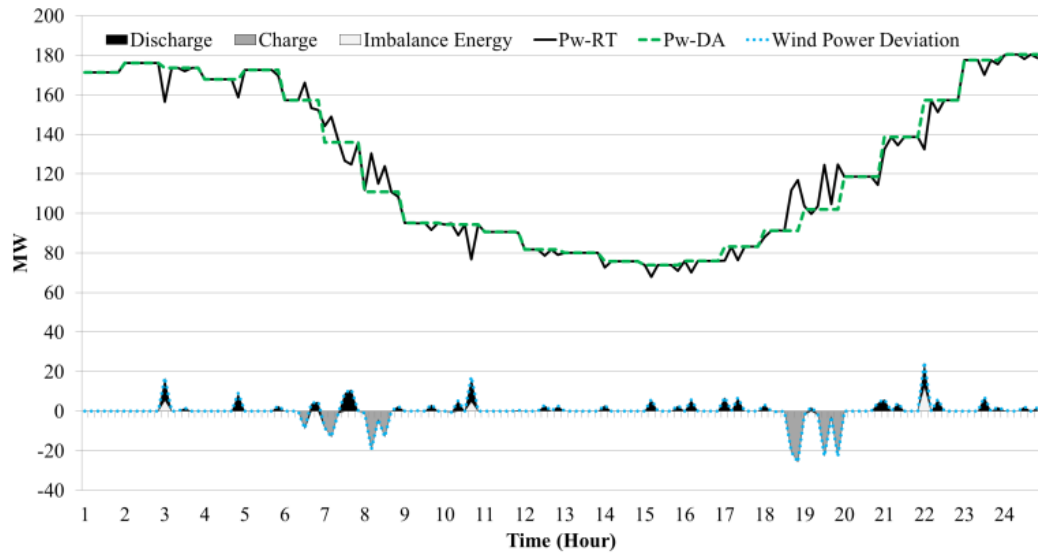


Fig. 3.11 Wind power generation schedule and battery energy storage profile in case B at 150 \$/MWh penalty price

3.5 Summary

Effective coordination between a WGenCo participating in the short-term electricity market and an EV aggregator participating in the energy and ancillary service markets increases the WGenCo's competitiveness and mitigates wind and EV energy imbalance threats. This chapter has introduced a stochastic optimal scheduling strategy. The strategy has been demonstrated on conventional systems (WGenCo without storage), WGenCo with ESS, and a power system with a coordinated EV-Wind energy exchange. The proposed strategy has been developed using model based-optimal decision making. It offers flexibility in selecting between the balancing, regulation services, and/or ESS for a WGenCo to compensate for wind power deviations. Comparisons of the coordinated EV-Wind energy exchange with the other two cases reveal that

- the coordinated EV-wind energy exchange ensures that the WGenCo payoff remains constant under changing penalty prices;
- the effectiveness of the coordinated EV-wind energy exchange becomes more apparent under higher penalty prices;
- benefits offered by EV aggregators of sufficient capacity include higher total payoffs, lower imbalance charges and less conservative day-ahead generation offers. However, a smaller number of EVs offer better results in comparison with the other two cases;
- the total energy imbalance adjusted by the balancing market decreases extremely under the coordinated EV-wind energy exchange.

Chapter 4

Pool Strategy of a Single Firm in Coordination with EV Load Aggregators

4.1 Introduction

It is vital for a firm (a producer including CGenCos and WGenCos) and the market operator to review equilibrium analysis to investigate new players influenced in the future smart grid [13, 56]. The WGenCos participate in electricity markets despite their uncertainty to maximize the expected payoff, similar to the other market producers with consideration of WGenCo as price-maker market player [11]. Also, some new market players (e.g. EV aggregators) have to compete with other market players while motivating the consumers to take part in the market [11-13].

However, the highest benefits for EV load aggregators are expected through participation in ancillary services [39]. The EV load aggregator meets to challenge

of considering both minimum tariff to motivate EV owners to take part in the market and high probability to be competitive on its own. Therefore, the determination of an optimal charging tariff is necessary to maximize the aggregator's profit and keep the current EV owners and attract new customers. The EV charging tariff can affect prices and the market outcomes.

This chapter investigates EV aggregator as price maker which is in the generation portfolio of a strategic producer including WGenCo and CGenCos. The main contributions of the chapter are:

- The development of an optimal bidding/offering strategy for the EV load aggregator providing the energy and ancillary services in coordination with a strategic producer in a pool-based electricity market with endogenous formation of DA and RT prices, and EV aggregator tariff.
- Optimization of EV charging profile with consideration of both endogenous fixed-rate and Time of Use (ToU) tariffs.
- The proposed formulation of a stochastic intra-hour bilevel optimization problem given by an MPEC including an upper-level problem and three lower-level problems for the sake of a) the strategic firm's profit maximization, and b) DA and RT social welfare, and EV owner's battery energy maximization, respectively.
- The analysis of the impact of EV numbers, both fixed-rate and ToU tariff on the price and market outcome.
- Consideration of the uncertainties related to wind speed, and EV owners' behavior based on driving patterns.

The rest of this chapter is organized as follows. Section 4.2 discusses the market framework. Section 4.3 provides a mathematical model formulation. Test of the

proposed market model through case studies is described in Section 4.4. Finally, Section 4.5 concludes, summarizing the chapter.

4.2 Proposed Market Framework

Two levels of market framework are introduced in this thesis which are wholesale-level and EV-level shown in Fig. 4.1. At the wholesale-level, a strategic firm including CGenCos, WGenCos, and EV aggregators submits supply-offers/demand-bids to the MO to participate in the day-ahead and real-time market directly. The MO runs the day-ahead market clearing process to determine day-ahead price, and power production schedules of CGenCos, WGenCos, LSEs and EVs. Also, the real-time market is cleared for each scenario based on achieved day-ahead data to determine real-time prices, regulation capacities, and wind power and load curtailments.

At the EV-level, EV owners connect to the EV aggregator in order to take part in the market indirectly. The EV aggregator determines maximum EV energy capacity and optimal charging tariff based on achieved day-ahead and real-time data.

The model assumptions are as follows:

1. The EV aggregator participates as dispatchable loads in the market by submitting strategic bid and offer prices to the day-ahead and the real-time markets, respectively at the wholesale-level. At the EV-level, EV owners connect to the EV aggregator to participate in the market for increasing the negotiation power of EV customers. Therefore, each EV fleet or owner is assigned to an EV aggregator through a contract [11]. The EV charging energy, charging tariff, and up and down regulation directly affect the strategic producer's expected profit. The amount of

regulation contracted is the total amount by which power can deviate from a baseline level (or POP). It is assumed that the EV aggregator can deviate from the day-ahead power-drawn (or POP) to balance energy by reducing or increasing their charging rate with consideration of EV aggregator energy constraints [6].

2. WGenCo submits strategic offer prices to the day-ahead and the real-time markets. Moreover, the wind power production excess/shortage, and curtailment power influence the strategic producer's expected profit [13].
3. CGenCo participates as dispatchable units in the market by submitting strategic offer prices to the day-ahead and the real-time markets, respectively. The energy production cost functions are assumed to be linear [99].
4. The LSEs submit bid prices for energy and curtailment (to be elastic) to the day-ahead and real market but not strategically [13, 65,93].
5. A transmission network is neglected for simplicity.
6. The price scheme used is the same as the scheme presented in [99]. Each generating unit is paid for its scheduled power production and EV loads are charged for their power consumption in the day-ahead market at the price ρ_t^{DA} . Additionally, each generating unit and EV aggregator is paid/charged for its regulation up/down at the prices $\rho_{t,i}^{RT,s}$ as repurchased prices [99].

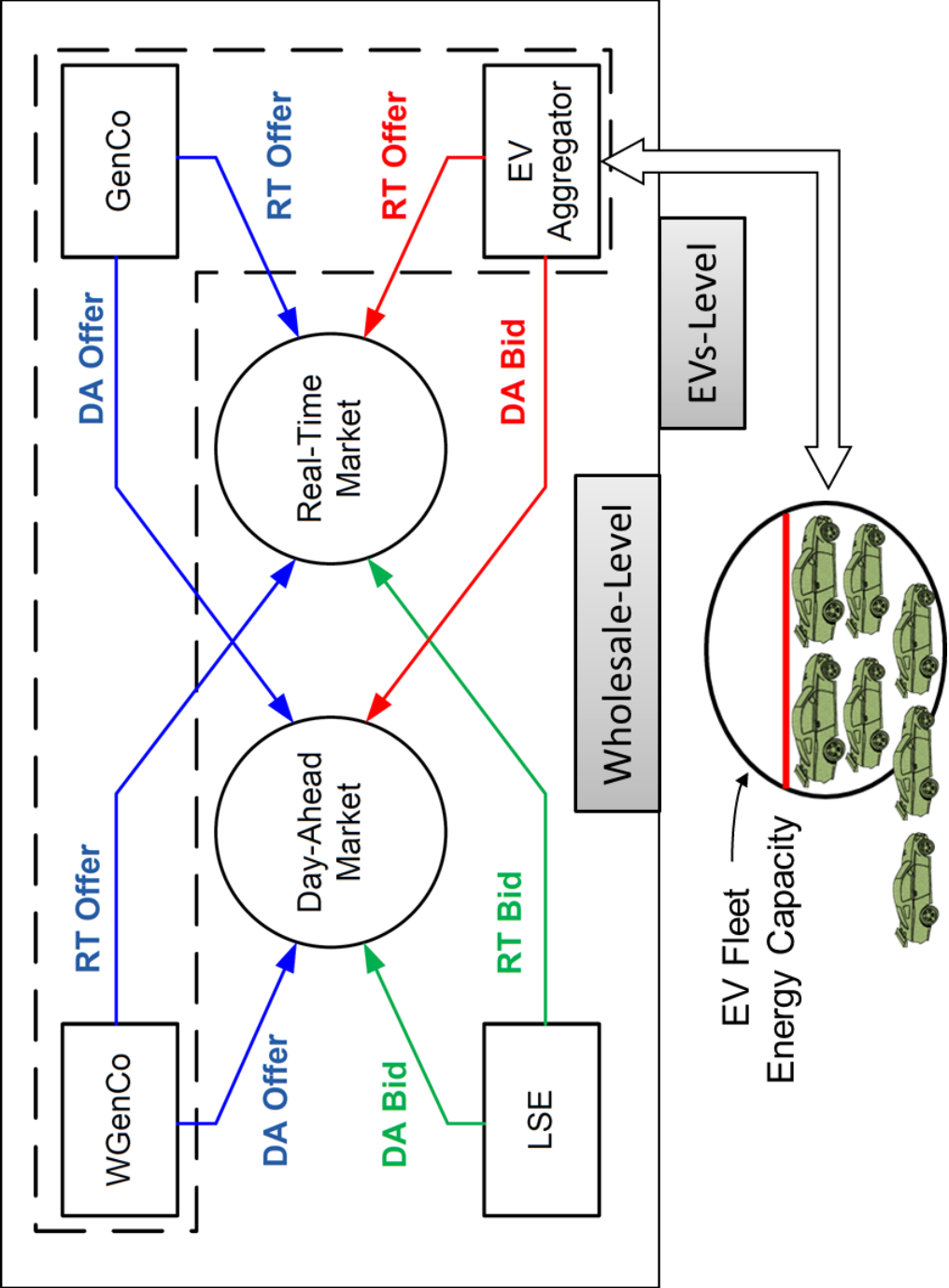


Fig. 4.1 The proposed wholesale & EV-levels structure of the electricity market (the firm's components are within the boundary of the broken lines).

4.3 Mathematical Model Formulation

A bilevel (hierarchical) model is used in this chapter to model the behaviour of a strategic firm.

4.3.1 Bilevel Model

A stochastic bilevel model is taken into account where an upper-level problem corresponds to a strategic firm's profit maximization, while the lower-level problems correspond to markets clearing for maximization of social welfare as shown in Fig. 4.2. The lower-level problems consist of the day-ahead market, real-time market, and EV energy market clearing which aim to maximize the social welfare and are subject to the power balance, and power limits.

The day-ahead lower level determines the day-ahead price and the power production/consumption quantities which directly affect the firm's expected profit in the upper-level problem, and EV energy and real-time market clearing in the lower-level problems. The real-time lower level presents the clearing of the real-time market based on EV numbers and wind power production scenarios which directly affect the firm's expected profit in the upper-level problem, and EV energy market in the lower-level problems. The EV energy lower level determines optimal charging tariff (ρ^T) based on achieved day-ahead and real-time data which directly affect the firm's expected profit in the upper-level problem. The strategic offering and decisions made by a strategic firm in the upper-level problem influence the market clearing outcomes in the lower-level problems.

The mathematical formulation of electricity markets is developed based on offering/bidding strategies given in [13, 93].

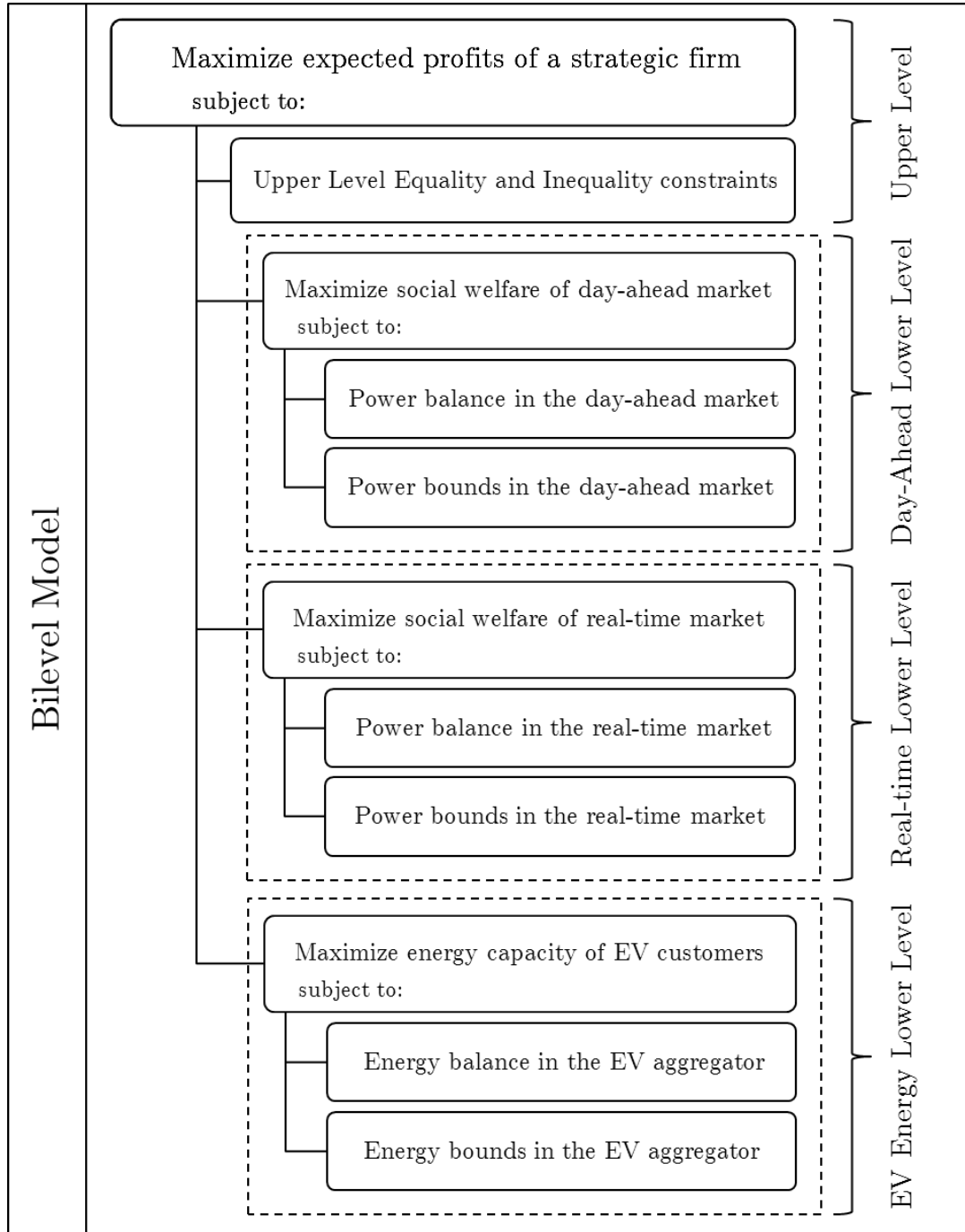


Fig. 4.2 Bilevel structure of the proposed wholesale & EV-levels structure of the electricity market.

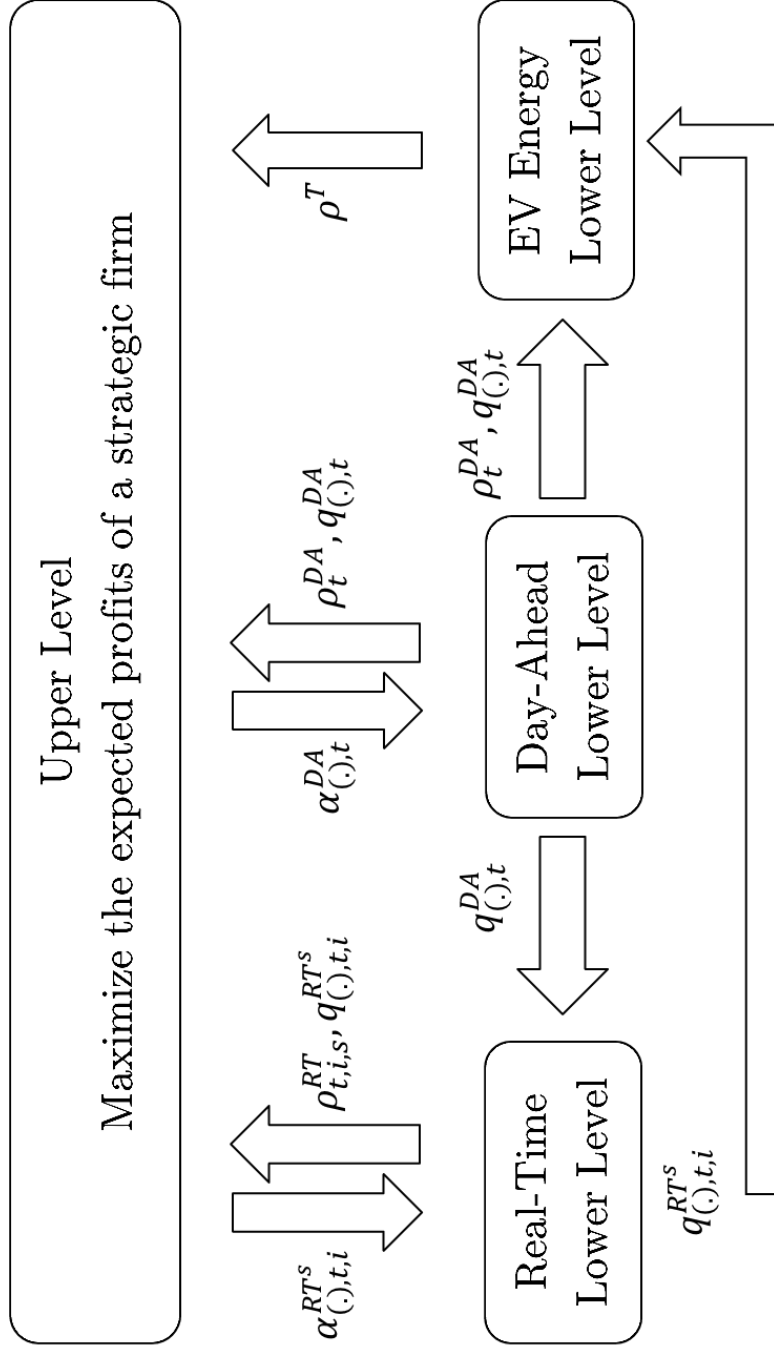


Fig. 4.3 Interrelation between the upper-level and lower level problems

4.3.1.1 Upper Level

The Objective function of maximizing the expected profits of a strategic firm which owns both CGenCos and WGenCos and constitutes unidirectional V2G services is as follows [100]:

$$\begin{aligned} \underset{\Omega_{prim}, \Omega_{dual}}{Max} \quad Profit^s = \\ \sum_s \pi_s \cdot [PF_s^{CGenCo} + PF_s^{WGenCo} + PF_s^{Agg}] \end{aligned} \quad (4.1)$$

The expected profit of CGenCos is revenue minus cost of generation in the day-ahead market, and revenue minus cost of regulation up/down in the real-time markets, given by (4.2):

$$\begin{aligned} PF_s^{CGenCo} = \sum_t \sum_g P_{g,t}^{DA} \cdot (\rho_t^{DA} - C_g) \\ + \frac{1}{N_I} \sum_i \sum_t \sum_g (R_{g,t,i}^{up^s} - R_{g,t,i}^{down^s}) (\rho_{t,i,s}^{RT} - C_g) \end{aligned} \quad (4.2)$$

The expected profit of WGenCos is revenue of generation in the day-ahead market, and revenue minus cost of excess/shortage generation in the real-time markets, given by (4.3):

$$\begin{aligned} PF_s^{WGenCo} = \sum_t \sum_w P_{w,t}^{DA} \cdot \rho_t^{DA} \\ - \frac{1}{N_I} \sum_i \sum_t \sum_w (P_{w,t}^{DA} + P_{w,t,i}^{CS} - P_{w,t,i}^{RT^s}) \cdot \rho_{t,i,s}^{RT} \end{aligned} \quad (4.3)$$

Finally, the EV aggregator's revenue is obtained by selling ancillary services, as well as selling energy to its clients at the tariff (ρ^T). The aggregator encourages EV owners to join in by offering an attractive price for charging which is low in comparison with petrol and energy prices. The EV aggregator's cost is associated

with buying energy for EV charging. Hence, the EV aggregator's payoff is represented as:

$$PF_s^{Agg} = -\sum_t \sum_{ev} POP_{ev,t} \rho_t^{DA} - \rho^T + \frac{1}{N_I} \sum_i \sum_t \sum_{ev} (R_{ev,t,i}^{up^s} - R_{ev,t,i}^{down^s})(\rho_{t,i,s}^{RT} - \rho^T) \quad (4.4)$$

The primal variables Ω_{prim} of the upper-level problem include positive offering/bidding variables $\alpha_{g,t}^{DA}$, $\alpha_{w,t}^{DA}$, $\beta_{ev,t}^{DA}$, $\alpha_{g,t,i}^{RT^s}$, $\alpha_{w,t,i}^{RT^s}$, $\alpha_{ev,t,i}^{RT^s}$ and variable sets

$$\Omega_{prim}^{DA} = \{\rho_t^{DA}, P_{g,t}^{DA}, P_{w,t}^{DA}, POP_{ev,t}\}, \text{ and } \Omega_{prim}^{RT} = \left\{ \rho_{t,i,s}^{RT}, R_{ev,t,i}^{up^s}, R_{ev,t,i}^{down^s}, R_{g,t,i}^{up^s}, R_{g,t,i}^{down^s}, P_{w,t,i}^{CS} \right\}.$$

4.3.1.2 Day-Ahead Lower Level

The day-ahead lower-level problem is formulated in this subsection. The day-ahead market clearing is addressed with the aim of maximization of social welfare given by (4.5):

$$Min_{\{\Omega_{prim}^{DA}, \Omega_{dual}^{DA}\}} \left[\begin{array}{l} \sum_{g,t} \alpha_{g,t}^{DA} P_{g,t}^{DA} + \sum_{w,t} \alpha_{w,t}^{DA} P_{w,t}^{DA} - \\ \sum_{d,t} B_{d,t}^{DA} L_{d,t}^{DA} - \sum_{ev,t} \beta_{ev,t}^{DA} POP_{ev,t} \end{array} \right] \quad (4.5)$$

The primal variables of the lower-level problem (4.5) are those in set Ω_{prim}^{DA} , and their dual variables in set Ω_{dual}^{DA} where dual variables are indicated following a colon at the constraints.

The energy balance in the day-ahead market is given by:

$$\sum_g P_{g,t}^{DA} + \sum_w P_{w,t}^{DA} - \sum_d L_{d,t}^{DA} - \sum_{ev} POP_{ev,t} = 0 \quad : \rho_t^{DA} \quad (4.6)$$

where dual variable ρ_t^{DA} provides the day-ahead equilibrium price.

Constraint for the EV POP is given by:

$$0 \leq POP_{ev,t} \leq P_{ev}^{max} : \mu_{ev,t}^{DA^{max}}, \mu_{ev,t}^{DA^{min}} \quad \forall ev, t \quad (4.7)$$

Constraints in (4.8) and (4.9) limit the scheduled power production of conventional and wind units, respectively.

$$0 \leq P_{g,t}^{DA} \leq P_g^{max} : \mu_{g,t}^{DA^{max}}, \mu_{g,t}^{DA^{min}} \quad \forall g, t \quad (4.8)$$

$$0 \leq P_{w,t}^{DA} \leq P_w^{max} : \mu_{w,t}^{DA^{max}}, \mu_{w,t}^{DA^{min}} \quad \forall w, t \quad (4.9)$$

The day-ahead scheduled demand is limited in (4.10).

$$0 \leq L_{d,t}^{DA} \leq L_d^{max} : \mu_{d,t}^{DA^{max}}, \mu_{d,t}^{DA^{min}} \quad \forall d, t \quad (4.10)$$

4.3.1.3 Real-Time Lower Level

The real-time lower-level problem represents the real-time market clearing with the aim of maximization of social welfare for scenarios s given by (4.11):

$$Min_{\{\Omega_{prim}^{RT}, \Omega_{dual}^{RT}\}} \left[\begin{array}{l} \sum_{g,t,i} (R_{g,t,i}^{up^s} - R_{g,t,i}^{down^s}) \cdot \alpha_{g,t,i}^{RT^s} + \\ \sum_{ev,t,i} (R_{ev,t,i}^{up^s} - R_{ev,t,i}^{down^s}) \cdot \alpha_{ev,t,i}^{RT^s} + \\ \sum_{w,t,i} (P_{w,t,i}^{CS} \cdot \alpha_{w,t,i}^{RT^s}) + \sum_{d,t,i} C_d^L L_{d,t,i}^{CS} \end{array} \right] \quad (4.11)$$

The primal variables of the lower-level problem (4.11) are those in set Ω_{prim}^{RT} , and their dual variables in set Ω_{dual}^{RT} where dual variables are shown at the corresponding constraints following a colon.

The energy balance in the real-time market is given by:

$$\sum_w (P_{w,t}^{DA} + P_{w,t,i}^{CS} - P_{w,t,i}^{RT^s}) - \sum_g (R_{g,t,i}^{up^s} - R_{g,t,i}^{down^s}) - \quad (4.12)$$

$$\sum_d L_{d,t,i}^{Cs} - \sum_{ev} (R_{ev,t,i}^{up^s} - R_{ev,t,i}^{down^s}) = 0 \quad : \rho_{t,i,s}^{RT} \quad \forall s, t, i$$

where dual variable $\rho_{t,i,s}^{RT}$ provides the real-time equilibrium prices.

The capacity limits for regulation down ($R_{ev,t,i}^{down^s}$) to increase the EV charging rate, and regulation up ($R_{ev,t,i}^{up^s}$) to decrease the EV charging rate are given in (4.13)-(4.16).

$$0 \leq R_{ev,t,i}^{up^s} \leq R_{ev}^{up^{max}} \quad : \mu_{ev,t,i,s}^{up^{max}}, \mu_{ev,t,i,s}^{up^{min}} \quad \forall ev, s, t, i \quad (4.13)$$

$$R_{ev,t,i}^{up^s} \leq POP_{ev,t} \quad : \mu_{ev,t,i,s}^{up} \quad \forall ev, s, t, i \quad (4.14)$$

$$0 \leq R_{ev,t,i}^{down^s} \leq R_{ev}^{d^{max}} \quad : \mu_{ev,t,i,s}^{d^{max}}, \mu_{ev,t,i,s}^{d^{min}} \quad \forall ev, s, t, i \quad (4.15)$$

$$POP_{ev,t} + R_{ev,t,i}^{down^s} \leq P_{ev}^{max} \quad : \mu_{ev,t,i,s}^{down} \quad \forall ev, s, t, i \quad (4.16)$$

Constraints (4.17) and (4.18) refer to the lower and upper bounds on the up and down regulations deployed from each dispatchable unit.

$$0 \leq R_{g,t,i}^{up^s} \leq R_g^{up^{max}} \quad : \mu_{g,t,i,s}^{up^{max}}, \mu_{g,t,i,s}^{up^{min}} \quad \forall g, s, t, i \quad (4.17)$$

$$P_{g,t}^{DA} + R_{g,t,i}^{up^s} \leq R_g^{up^{max}} \quad : \mu_{g,t,i,s}^{up} \quad \forall g, s, t, i \quad (4.18)$$

The constraints (4.19) and (4.20) guarantee that the power productions of conventional units are less than their capacities.

$$0 \leq R_{g,t,i}^{down^s} \leq R_g^{d^{max}} \quad : \mu_{g,t,i,s}^{d^{max}}, \mu_{g,t,i,s}^{d^{min}} \quad \forall g, s, t, i \quad (4.19)$$

$$R_{g,t,i}^{down^s} \leq P_{g,t}^{DA} \quad : \mu_{g,t,i,s}^{down} \quad \forall g, s, t, i \quad (4.20)$$

The constraints (4.21) and (4.22) limit the minimum and maximum for the wind power and load demand curtailment.

$$0 \leq P_{w,t,i}^{Cs} \leq P_{w,t,i}^{RT^s} : \mu_{w,t,i,s}^{C^{max}}, \mu_{w,t,i,s}^{C^{min}} \quad \forall w, s, t, i \quad (4.21)$$

$$0 \leq L_{d,t,i}^{Cs} \leq L_d^{max} : \mu_{d,t,i,s}^{C^{max}}, \mu_{d,t,i,s}^{C^{min}} \quad \forall d, s, t, i \quad (4.22)$$

4.3.1.4 EV Energy Lower Level

The EV Energy lower-level problem aims to maximize EV energy capacity given in

$$\underset{\{E_{ev,t}^{DA}, \Omega_{dual}^{EV}\}}{Min} \left[- \sum_{ev,t} \rho_t^{DA} E_{ev,t}^{DA} \right] \quad (4.23)$$

The energy balance equation for the EV fleet is given in

$$\begin{aligned} & \sum_{ev} E_{ev,t,i}^s - \sum_{ev} E_{ev,t,i-1}^s - (1 - N_{ev,t,i}^s) \cdot D_{ev,t,i}^s \\ & - \frac{1}{N_I} \sum_{ev} (POP_{ev,t} - R_{ev,t,i}^{up^s} + R_{ev,t,i}^{down^s}) = 0 \quad : \rho^T, \quad \forall s, t, i \end{aligned} \quad (4.24)$$

$$E_{ev,t}^{DA} = \frac{1}{N_I} \sum_s \sum_i E_{ev,t,i}^s \quad \forall ev, t \quad (4.25)$$

The EV energy constraint is presented in

$$\begin{aligned} & \frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Min} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{min} \\ & \leq E_{ev,t}^{DA} \\ & \leq \frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Max} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{max} : \mu_{ev,t}^{EEV^{max}}, \mu_{ev,t}^{EEV^{min}} \quad \forall ev, s, t, i \end{aligned} \quad (4.26)$$

4.3.2 Mathematical Program with Equilibrium Constraints

The stochastic bilevel model including multi-optimization problems transforms into a single optimization problem as a single-level stochastic MPEC [71]. The

lower problems are continuous linear and can be replaced by their KKT conditions.

4.3.2.1 KKT Conditions Corresponding to the Day-ahead Lower Level

The corresponding Lagrangian function \mathcal{L}^{DA} of a day-ahead clearing problem is defined as follows:

$$\begin{aligned}
 \partial \mathcal{L}^{DA} = & \sum_{g,t} \alpha_{g,t}^{DA} P_{g,t}^{DA} + \sum_{w,t} \alpha_{w,t}^{DA} P_{w,t}^{DA} \\
 & - \sum_{d,t} B_{d,t}^{DA} L_{d,t}^{DA} - \sum_{ev,t} \beta_{ev,t}^{DA} POP_{ev,t} \\
 & + \sum_t \rho_t^{DA} \left(\sum_g P_{g,t}^{DA} + \sum_w P_{w,t}^{DA} - \sum_d L_{d,t}^{DA} - \sum_{ev} POP_{ev,t} \right) \\
 & + \sum_{ev,t} \mu_{ev,t}^{DA^{max}} (P_{ev}^{max} - POP_{ev,t}) - \sum_{ev,t} \mu_{ev,t}^{DA^{min}} POP_{ev,t} \\
 & + \sum_{g,t} \mu_{g,t}^{DA^{max}} (P_g^{max} - P_{g,t}^{DA}) - \sum_{g,t} \mu_{g,t}^{DA^{min}} P_{g,t}^{DA} \\
 & + \sum_{w,t} \mu_{w,t}^{DA^{max}} (P_w^{max} - P_{w,t}^{DA}) - \sum_{w,t} \mu_{w,t}^{DA^{min}} P_{w,t}^{DA} \\
 & + \sum_{d,t} \mu_{d,t}^{DA^{max}} (L_d^{max} - L_{d,t}^{DA}) - \sum_{d,t} \mu_{d,t}^{DA^{min}} L_{d,t}^{DA}
 \end{aligned} \tag{4.27}$$

The first-order KKT conditions associated with the day-ahead lower level according to Lagrangian function (4.27) are derived as given by:

$$\frac{\partial \mathcal{L}^{DA}}{\partial POP_{ev,t}} = -\beta_{ev,t}^{DA} + \rho_t^{DA} + \mu_{ev,t}^{DA^{max}} - \mu_{ev,t}^{DA^{min}} = 0 \quad \forall ev, t \tag{4.27a}$$

$$\frac{\partial \mathcal{L}^{DA}}{\partial P_{g,t}^{DA}} = +\alpha_{g,t}^{DA} - \rho_t^{DA} + \mu_{g,t}^{DA^{max}} - \mu_{g,t}^{DA^{min}} = 0 \quad \forall g, t \quad (4.27b)$$

$$\frac{\partial \mathcal{L}^{DA}}{\partial P_{w,t}^{DA}} = +\alpha_{w,t}^{DA} - \rho_t^{DA} + \mu_{w,t}^{DA^{max}} - \mu_{w,t}^{DA^{min}} = 0 \quad \forall w, t \quad (4.27c)$$

$$\frac{\partial \mathcal{L}^{DA}}{\partial L_{d,t}^{DA}} = -B_{d,t}^{DA} + \rho_t^{DA} + \mu_{d,t}^{DA^{max}} - \mu_{d,t}^{DA^{min}} = 0 \quad \forall d, t \quad (4.27d)$$

$$0 \leq P_{ev}^{max} - POP_{ev,t} \perp \mu_{ev,t}^{DA^{max}} \geq 0 \quad \forall ev, t \quad (4.27e)$$

$$0 \leq P_g^{max} - P_{g,t}^{DA} \perp \mu_{g,t}^{DA^{max}} \geq 0 \quad \forall g, t \quad (4.27f)$$

$$0 \leq P_w^{max} - P_{w,t}^{DA} \perp \mu_{w,t}^{DA^{max}} \geq 0 \quad \forall w, t \quad (4.27g)$$

$$0 \leq L_d^{max} - L_{d,t}^{DA} \perp \mu_{d,t}^{DA^{max}} \geq 0 \quad \forall d, t \quad (4.27h)$$

$$0 \leq POP_{ev,t} \perp \mu_{ev,t}^{DA^{min}} \geq 0 \quad \forall ev, t \quad (4.27i)$$

$$0 \leq P_{g,t}^{DA} \perp \mu_{g,t}^{DA^{min}} \geq 0 \quad \forall g, t \quad (4.27j)$$

$$0 \leq P_{w,t}^{DA} \perp \mu_{w,t}^{DA^{min}} \geq 0 \quad \forall w, t \quad (4.27k)$$

$$0 \leq L_{d,t}^{DA} \perp \mu_{d,t}^{DA^{min}} \geq 0 \quad \forall d, t \quad (4.27l)$$

where \perp denotes the inner product of two vectors equal to zero [57].

4.3.2.2 KKT Conditions Corresponding to the Real-time Lower Level

The corresponding Lagrangian function \mathcal{L}^{RT} of the real-time clearing problems is defined as follows:

$$\begin{aligned}
 \mathcal{L}^{RT} = & \sum_{w,t,i} (P_{w,t,i}^{Cs} \cdot \alpha_{w,t,i}^{RTs}) + \sum_{d,t,i} C_d^L L_{d,t,i}^{Cs} + \sum_{ev,t,i} (R_{ev,t,i}^{ups} - R_{ev,t,i}^{downs}) \cdot \alpha_{g,t,i}^{RTs} \\
 & + \sum_{g,t,i} (R_{g,t,i}^{ups} - R_{g,t,i}^{downs}) \cdot \alpha_{g,t,i}^{RTs} \\
 & + \sum_t \rho_{t,i,s}^{RT} \left(\sum_w (P_{w,t}^{DA} + P_{w,t,i}^{Cs} - P_{w,t,i}^{RTs}) \right. \\
 & - \sum_g (R_{g,t,i}^{ups} - R_{g,t,i}^{downs}) - \sum_d L_{d,t,i}^{Cs} \\
 & \left. - \sum_{ev} (R_{ev,t,i}^{ups} - R_{ev,t,i}^{downs}) \right) \\
 & + \sum_{g,t,i} \mu_{g,t,i,s}^{up^{max}} (R_g^{up^{max}} - R_{g,t,i}^{ups}) - \sum_{g,t,i} \mu_{g,t,i,s}^{up^{min}} R_{g,t,i}^{ups} \\
 & + \sum_{g,t,i} \mu_{ev,t,i,s}^{up} (R_g^{up^{max}} - P_{g,t}^{DA} - R_{g,t,i}^{ups}) \\
 & + \sum_{g,t,i} \mu_{g,t,i,s}^{d^{max}} (R_g^{d^{max}} - R_{g,t,i}^{downs}) - \sum_{g,t,i} \mu_{g,t,i,s}^{d^{min}} R_{g,t,i}^{downs} \\
 & + \sum_{g,t,i} \mu_{g,s,RT}^{down} (P_{g,t}^{DA} - R_{g,t,i}^{downs}) \\
 & + \sum_{ev,t,i} \mu_{ev,t,i,s}^{up^{max}} (R_{ev}^{up^{max}} - R_{ev,t,i}^{ups}) - \sum_{ev,t,i} \mu_{ev,t,i,s}^{up^{min}} R_{ev,t,i}^{ups} \\
 & + \sum_{ev,t,i} \mu_{ev,t,i,s}^{up} (POP_{ev,t} - R_{ev,t,i}^{ups}) \\
 & + \sum_{ev,t,i} (R_{ev}^{d^{max}} - R_{ev,t,i}^{downs}) \mu_{ev,t,i,s}^{d^{max}} - \sum_{ev,t,i} \mu_{ev,t,i,s}^{d^{min}} R_{ev}^{d^{max}} \\
 & + \sum_{ev,t,i} \mu_{ev,t,i,s}^d (P_{ev}^{max} - POP_{ev,t} - R_{ev,t,i}^{downs}) \\
 & + \sum_{d,t,i} \mu_{d,t,i,s}^{c^{max}} (L_d^{max} - L_{d,t,i}^{Cs}) - \sum_{d,t,i} \mu_{d,t,i,s}^{c^{min}} L_{d,t,i}^{Cs} \\
 & + \sum_{wt,i} \mu_{w,t,i,s}^{c^{max}} (P_{w,t,i}^{RTs} - P_{w,t,i}^{Cs}) - \sum_{wt,i} \mu_{w,t,i,s}^{c^{min}} P_{w,t,i}^{Cs} \tag{4.28}
 \end{aligned}$$

The first-order KKT conditions associated with the real-time lower level according to Lagrangian function (4.28) are derived as given by”

$$\frac{\partial \mathcal{L}^{RT}}{\partial R_{ev,t,i}^{up^s}} = \mu_{ev,t,i,s}^{up^{max}} - \mu_{ev,t,i,s}^{up^{min}} + \mu_{ev,t,i,s}^{up} + \alpha_{ev,t,i}^{RT^s} - \rho_{t,i,s}^{RT} = 0 \quad \forall ev, s, t, i \quad (4.28a)$$

$$\frac{\partial \mathcal{L}^{RT}}{\partial R_{ev,t,i}^{d^s}} = \mu_{ev,t,i,s}^{d^{max}} - \mu_{ev,t,i,s}^{d^{min}} + \mu_{ev,t,i,s}^{down} - \alpha_{ev,t,i}^{RT^s} + \rho_{t,i,s}^{RT} = 0 \quad \forall ev, s, t, i \quad (4.28b)$$

$$\frac{\partial \mathcal{L}^{RT}}{\partial R_{g,t,i}^{up^s}} = \mu_{g,t,i,s}^{up^{max}} - \mu_{g,t,i,s}^{up^{min}} + \mu_{g,t,i,s}^{up} + \alpha_{g,t,i}^{RT^s} - \rho_{t,i,s}^{RT} = 0 \quad \forall g, s, t, i \quad (4.28c)$$

$$\frac{\partial \mathcal{L}^{RT}}{\partial R_{g,t,i}^{d^s}} = \mu_{g,t,i,s}^{d^{max}} - \mu_{g,t,i,s}^{d^{min}} + \mu_{g,s,RT}^{down} - \alpha_{g,t,i}^{RT^s} + \rho_{t,i,s}^{RT} = 0 \quad \forall g, s, t, i \quad (4.28d)$$

$$\frac{\partial \mathcal{L}^{RT}}{\partial P_{w,t,i}^{C^s}} = \mu_{w,t,i,s}^{c^{max}} - \mu_{w,t,i,s}^{c^{min}} + \alpha_{w,t,i}^{RT^s} + \rho_{t,i,s}^{RT} = 0 \quad \forall w, s, t, i \quad (4.28e)$$

$$\frac{\partial \mathcal{L}^{RT}}{\partial L_{d,t,i}^{C^s}} = -\rho_{t,i,s}^{RT} + \mu_{d,t,i,s}^{c^{max}} - \mu_{d,t,i,s}^{c^{min}} + C_{d,t}^L = 0 \quad \forall d, s, t, i \quad (4.28f)$$

$$0 \leq R_{ev}^{up^{max}} - R_{ev,t,i}^{up^s} \perp \mu_{ev,t,i,s}^{up^{max}} \geq 0 \quad \forall ev, s, t, i \quad (4.28g)$$

$$0 \leq POP_{ev,t} - R_{ev,t,i}^{up^s} \perp \mu_{ev,t,i,s}^{up} \geq 0 \quad \forall ev, s, t, i \quad (4.28h)$$

$$0 \leq R_{ev}^{d^{max}} - R_{ev,t,i}^{down^s} \perp \mu_{ev,t,i,s}^{d^{max}} \geq 0 \quad \forall ev, s, t, i \quad (4.28i)$$

$$0 \leq P_{ev}^{max} - POP_{ev,t} - R_{ev,t,i}^{down^s} \perp \mu_{ev,s,RT}^{down} \geq 0 \quad \forall ev, s, t, i \quad (4.28j)$$

$$0 \leq R_g^{up^{max}} - R_{g,t,i}^{up^s} \perp \mu_{g,t,i,s}^{up^{max}} \geq 0 \quad \forall g, s, t, i \quad (4.28k)$$

$$0 \leq R_g^{up^{max}} - P_{g,t}^{DA} - R_{g,t,i}^{up^s} \perp \mu_{g,t,i,s}^{up} \geq 0 \quad \forall g, s, t, i \quad (4.28l)$$

$$0 \leq R_g^{d^{max}} - R_{g,t,i}^{down^s} \perp \mu_{g,t,i,s}^{d^{max}} \geq 0 \quad \forall g, s, t, i \quad (4.28m)$$

$$0 \leq P_{g,t}^{DA} - R_{g,t,i}^{down^s} \perp \mu_{g,s,RT}^{down} \geq 0 \quad \forall g, s, t, i \quad (4.28n)$$

$$0 \leq P_{w,t,i}^{RT^s} - P_{w,t,i}^{C^s} \perp \mu_{w,t,i,s}^{c^{max}} \geq 0 \quad \forall w, s, t, i \quad (4.28o)$$

$$0 \leq L_d^{max} - L_{d,t,i}^{C^s} \perp \mu_{d,t,i,s}^{c^{max}} \geq 0 \quad \forall d, s, t, i \quad (4.28p)$$

$$0 \leq R_{ev,t,i}^{up^s} \perp \mu_{ev,t,i,s}^{up^{min}} \geq 0 \quad \forall ev, s, t, i \quad (4.28q)$$

$$0 \leq R_{ev,t,i}^{down^s} \perp \mu_{ev,t,i,s}^{d^{min}} \geq 0 \quad \forall ev, s, t, i \quad (4.28r)$$

$$0 \leq R_{g,t,i}^{up^s} \perp \mu_{g,t,i,s}^{up^{min}} \geq 0 \quad \forall g, s, t, i \quad (4.28s)$$

$$0 \leq R_{g,t,i}^{down^s} \perp \mu_{g,t,i,s}^{d^{min}} \geq 0 \quad \forall g, s, t, i \quad (4.28t)$$

$$0 \leq P_{w,t,i}^{Cs} \perp \mu_{w,t,i,s}^{c^{min}} \geq 0 \quad \forall w, s, t, i \quad (4.28x)$$

$$0 \leq L_{d,t,i}^{Cs} \perp \mu_{d,t,i,s}^{c^{min}} \geq 0 \quad \forall d, s, t, i \quad (4.28y)$$

4.3.2.3 KKT Conditions Corresponding to the EV Lower Level

The corresponding Lagrangian function \mathcal{L}^{EV} of the EV lower-level problem is defined as follows:

$$\begin{aligned} \mathcal{L}^{EV} = & - \sum_{ev,t} \rho_t^{DA} E_{ev,t}^{DA} \\ & + \sum_t \rho^T \left(\frac{1}{N_I} \sum_s \sum_i \left[\sum_{ev} E_{ev,t,i}^s \right. \right. \\ & - \sum_{ev} E_{ev,t,i-1}^s - (1 - N_{ev,t,i}^s) \cdot D_{ev,t,i}^s \\ & \left. \left. - \frac{1}{N_I} \sum_{ev} (POP_{ev,t} - R_{ev,t,i}^{up^s} + R_{ev,t,i}^{down^s}) \right] \right) \\ & + \sum_t \mu_{ev,t}^{EEV^{max}} \left(E_{ev,t}^{DA} - \frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Max} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{max} \right) \\ & - \sum_t \mu_{ev,t}^{EEV^{min}} \left(\frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Min} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{min} - E_{ev,t}^{DA} \right) \end{aligned} \quad (4.29)$$

The first-order KKT conditions associated with the real-time lower level according to Lagrangian function (4.29) are derived as given by

$$\frac{\partial \mathcal{L}^{EV}}{\partial E_{ev,t}^{DA}} = \rho^T - \rho_t^{DA} + \mu_{ev,t}^{EEV^{max}} - \mu_{ev,t}^{EEV^{min}} = 0 \quad \forall ev, t \quad (4.29a)$$

$$0 \leq E_{ev,t}^{DA} - \frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Max} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{max} \perp \mu_{ev,t}^{EEV^{max}} \geq 0 \quad \forall ev, t \quad (4.29b)$$

$$0 \leq \frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Min} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{min} - E_{ev,t}^{DA} \perp \mu_{ev,t}^{EEV^{min}} \geq 0 \quad \forall ev, t \quad (4.29c)$$

4.3.2.4 Strong Duality Theorem Corresponding to the Day-ahead Lower Level

Equation (4.30) enforces the strong duality equality associated with the day-ahead objective function.

$$\begin{aligned} & \sum_{g,t} \alpha_{g,t}^{DA} P_{g,t}^{DA} + \sum_{w,t} \alpha_{w,t}^{DA} P_{w,t}^{DA} - \sum_{d,t} B_{d,t}^{DA} L_{d,t}^{DA} - \sum_{ev,t} \beta_{ev,t}^{DA} POP_{ev,t} \\ & + \sum_{ev,t} \mu_{ev,t}^{DA^{max}} P_{ev}^{max} + \sum_{g,t} \mu_{g,t}^{DA^{max}} (P_g^{max}) \\ & + \sum_{w,t} \mu_{w,t}^{DA^{max}} (P_w^{max}) + \sum_{d,t} \mu_{d,t}^{DA^{max}} L_d^{max} = 0 \end{aligned} \quad (4.30)$$

4.3.2.5 Strong Duality Theorem Corresponding to the Real-time Lower Level

Equation (4.31) enforces the strong duality equality associated with the day-ahead objective function.

$$\begin{aligned}
 & \sum_{w,t,i} (P_{w,t,i}^{Cs} \cdot \alpha_{w,t,i}^{RT^s}) + \sum_{d,t,i} C_d^L L_{d,t,i}^{Cs} + \sum_{ev,t,i} (R_{ev,t,i}^{up^s} - R_{ev,t,i}^{down^s}) \cdot \alpha_{g,t,i}^{RT^s} \\
 & + \sum_{g,t,i} (R_{g,t,i}^{up^s} - R_{g,t,i}^{down^s}) \cdot \alpha_{g,t,i}^{RT^s} + \sum_{d,t,i} \mu_{d,t,i,s}^{c^{max}} L_d^{max} \\
 & + \sum_{g,t,i} \mu_{g,t,i,s}^{up^{max}} (R_g^{up^{max}}) + \sum_{g,t,i} \mu_{ev,t,i,s}^{up} (R_g^{up^{max}} - P_{g,t}^{DA}) \\
 & + \sum_{ev,t,i} \mu_{ev,t,i,s}^{up^{max}} R_{ev}^{up^{max}} + \sum_{ev,t,i} \mu_{ev,t,i,s}^{up} (POP_{ev,t}) \\
 & + \sum_{wt,i} \mu_{w,t,i,s}^{c^{max}} (P_{w,t,i}^{RT^s}) + \sum_{ev,t,i} \mu_{ev,t,i,s}^d (P_{ev}^{max} - POP_{ev,t}) \\
 & + \sum_{g,t,i} \mu_{g,t,i,s}^{d^{max}} (R_g^{d^{max}}) + \sum_t \rho_{t,i,s}^{RT} \left(\sum_w (P_{w,t}^{DA} - P_{w,t,i}^{RT^s}) \right) \\
 & + \sum_{g,t,i} \mu_{g,t,i,s}^{down} (P_{g,t}^{DA}) + \sum_{ev,t,i} R_{ev}^{d^{max}} \mu_{ev,t,i,s}^{d^{max}} = 0
 \end{aligned} \tag{4.31}$$

4.3.2.6 Strong Duality Theorem Corresponding to the EV Lower Level

Equation (4.32) enforces the strong duality equality associated with EV lower problem.

$$\begin{aligned}
 & - \sum_{ev,t} \rho_t^{DA} E_{ev,t}^{DA} \\
 & + \sum_t \rho_t^T \left(\frac{1}{N_I} \sum_s \sum_i \left[- \sum_{ev} E_{ev,t,i-1}^s - (1 - N_{ev,t,i}^s) \cdot D_{ev,t,i}^s \right. \right. \\
 & \left. \left. - \frac{1}{N_I} \sum_{ev} (POP_{ev,t} - R_{ev,t,i}^{up^s} + R_{ev,t,i}^{down^s}) \right] \right) \\
 & + \sum_t \mu_{ev,t}^{EEV^{max}} \left(\frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Max} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{max} \right) \\
 & - \sum_t \mu_{ev,t}^{EEV^{min}} \left(\frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Min} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{min} \right) = 0
 \end{aligned} \tag{4.31}$$

4.3.3 Mixed-Integer Linear Programming

The MPEC are converted to a MILP by the linearizing of two nonlinearities including complementarity conditions and nonlinear terms as follows.

4.3.3.1 Linearization of Complementarity Conditions

The complementarity conditions in the form of $0 \leq P \perp \mu \geq 0$ can be linearized by

$$P \geq 0, \mu \geq 0, \mu \leq b \cdot M_1, P \leq 1 - b \cdot M_2 \quad (4.32)$$

where b is an auxiliary binary variable, and M_1 and M_2 are large enough constants. Note that the values of M_1 and M_2 are selected by trial-and error approach as used in [21].

- 1) Mixed-integer linear equivalents of the complementarity conditions in section 4.3.2.1 from equation (4.27e) to (4.27l):

$$\mu_{ev,t}^{DA^{max}} \geq 0, P_{ev}^{max} - POP_{ev,t} \geq 0 \quad \forall ev, t \quad (4.27e1)$$

$$P_{ev}^{max} - POP_{ev,t} \leq b_{ev,t}^{DA^{max}} X_E^{DA} \quad \forall ev, t \quad (4.27e2)$$

$$\mu_{ev,t}^{DA^{max}} \leq (1 - b_{ev,t}^{DA^{max}}) Y_E^{DA} \quad \forall ev, t \quad (4.27e3)$$

$$\mu_{g,t}^{DA^{max}} \geq 0, P_g^{max} - P_{g,t}^{DA} \geq 0 \quad \forall g, t \quad (4.27f1)$$

$$P_g^{max} - P_{g,t}^{DA} \leq b_{g,t}^{DA^{max}} X_G^{DA} \quad \forall g, t \quad (4.27f2)$$

$$\mu_{g,t}^{DA^{max}} \leq (1 - b_{g,t}^{DA^{max}}) Y_G^{DA} \quad \forall g, t \quad (4.27f3)$$

$$\mu_{w,t}^{DA^{max}} \geq 0, P_w^{max} - P_{w,t}^{DA} \geq 0 \quad \forall w, t \quad (4.27g1)$$

$$P_w^{max} - P_{w,t}^{DA} \leq b_{w,t}^{DA^{max}} X_W^{DA} \quad \forall w, t \quad (4.27g2)$$

$$\mu_{w,t}^{DA^{max}} \leq (1 - b_{w,t}^{DA^{max}}) Y_W^{DA} \quad \forall w, t \quad (4.27g3)$$

$$\mu_{d,t}^{DA^{max}} \geq 0, L_d^{max} - L_{d,t}^{DA} \geq 0 \quad \forall d, t \quad (4.27h1)$$

$$L_d^{max} - L_{d,t}^{DA} \leq b_{d,t}^{DA^{max}} X_L^{DA} \quad \forall d, t \quad (4.27h2)$$

$$\mu_{d,t}^{DA^{max}} \leq (1 - b_{d,t}^{DA^{max}}) Y_L^{DA} \quad \forall d, t \quad (4.27h3)$$

$$\mu_{ev,t}^{DA^{min}} \geq 0, POP_{ev,t} \geq 0 \quad \forall ev, t \quad (4.27i1)$$

$$POP_{ev,t} \leq b_{ev,t}^{DA^{min}} X_E^{DA} \quad \forall ev, t \quad (4.27i2)$$

$$\mu_{ev,t}^{DA^{max}} \leq (1 - b_{ev,t}^{DA^{min}}) Y_E^{DA} \quad \forall ev, t \quad (4.27i3)$$

$$\mu_{g,t}^{DA^{min}} \geq 0, P_{g,t}^{DA} \geq 0 \quad \forall g, t \quad (4.27j1)$$

$$P_{g,t}^{DA} \leq b_{g,t}^{DA^{min}} X_G^{DA} \quad \forall g, t \quad (4.27j2)$$

$$\mu_{g,t}^{DA^{min}} \leq (1 - b_{g,t}^{DA^{min}}) Y_G^{DA} \quad \forall g, t \quad (4.27j3)$$

$$\mu_{w,t}^{DA^{min}} \geq 0, P_{w,t}^{DA} \geq 0 \quad \forall w, t \quad (4.27k1)$$

$$P_{w,t}^{DA} \leq b_{w,t}^{DA^{min}} X_W^{DA} \quad \forall w, t \quad (4.27k2)$$

$$\mu_{w,t}^{DA^{min}} \leq (1 - b_{w,t}^{DA^{min}}) Y_W^{DA} \quad \forall w, t \quad (4.28k3)$$

$$\mu_{d,t}^{DA^{min}} \geq 0, L_{d,t}^{DA} \geq 0 \quad \forall d, t \quad (4.27l1)$$

$$L_{d,t}^{DA} \leq b_{d,t}^{DA^{min}} X_L^{DA} \quad \forall d, t \quad (4.27l2)$$

$$\mu_{d,t}^{DA^{min}} \leq (1 - b_{d,t}^{DA^{min}}) Y_L^{DA} \quad \forall d, t \quad (4.27l3)$$

where X_E^{DA} , X_G^{DA} , X_W^{DA} , X_L^{DA} , Y_E^{DA} , Y_G^{DA} , Y_W^{DA} , Y_L^{DA} are large enough positive constants and $b_{(\cdot),t}^{DA^{(\cdot)}}$ are binary variables.

- 2) Mixed-integer linear equivalents of the complementarity conditions in section 4.3.2.2 from equation (4.28g) to (4.28y):

$$\mu_{ev,t,i,s}^{up^{max}} \geq 0, R_{ev}^{up^{max}} - R_{ev,t,i}^{up^s} \geq 0 \quad \forall ev, s, t, i \quad (4.28g1)$$

$$R_{ev}^{up^{max}} - R_{ev,t,i}^{up^s} \leq b_{ev,t,i,s}^{up^{max}} X_E^{RT} \quad \forall ev, s, t, i \quad (4.28g2)$$

$$\mu_{ev,t,i,s}^{up^{max}} \leq (1 - b_{ev,t,i,s}^{up^{max}}) Y_E^{RT} \quad \forall ev, s, t, i \quad (4.28g3)$$

$$\mu_{ev,t,i,s}^{up} \geq 0, POP_{ev,t} - R_{ev,t,i}^{up^s} \geq 0 \quad \forall ev, s, t, i \quad (4.28h1)$$

$$POP_{ev,t} - R_{ev,t,i}^{up^s} \leq b_{ev,t,i,s}^{up} X_E^{RT} \quad \forall ev, s, t, i \quad (4.28h2)$$

$$\mu_{ev,t,i,s}^{up} \leq (1 - b_{ev,t,i,s}^{up}) Y_E^{RT} \quad \forall ev, s, t, i \quad (4.28h3)$$

$$\mu_{ev,t,i,s}^{d^{max}} \geq 0, R_{ev}^{d^{max}} - R_{ev,t,i}^{down^s} \geq 0 \quad \forall ev, s, t, i \quad (4.28i1)$$

$$R_{ev}^{d^{max}} - R_{ev,t,i}^{down^s} \leq b_{ev,t,i,s}^{d^{max}} X_E^{RT} \quad \forall ev, s, t, i \quad (4.28i2)$$

$$\mu_{ev,t,i,s}^{d^{max}} \leq (1 - b_{ev,t,i,s}^{d^{max}}) Y_E^{RT} \quad \forall ev, s, t, i \quad (4.28i3)$$

$$\mu_{ev,s,RT}^{down} \geq 0, P_{ev}^{max} - POP_{ev,t} - R_{ev,t,i}^{down^s} \geq 0 \quad \forall ev, s, t, i \quad (4.28j1)$$

$$P_{ev}^{max} - POP_{ev,t} - R_{ev,t,i}^{down^s} \leq b_{ev,s,RT}^{down} X_E^{RT} \quad \forall ev, s, t, i \quad (4.28j2)$$

$$\mu_{ev,s,RT}^{down} \leq (1 - b_{ev,s,RT}^{down}) Y_E^{RT} \quad \forall ev, s, t, i \quad (4.28j3)$$

$$\mu_{g,t,i,s}^{up^{max}} \geq 0, R_g^{up^{max}} - R_{g,t,i}^{up^s} \geq 0 \quad \forall g, s, t, i \quad (4.28k1)$$

$$R_g^{up^{max}} - R_{g,t,i}^{up^s} \leq b_{g,t,i,s}^{up^{max}} X_G^{RT} \quad \forall g, s, t, i \quad (4.28k2)$$

$$\mu_{g,t,i,s}^{up^{max}} \leq (1 - b_{g,t,i,s}^{up^{max}}) Y_G^{RT} \quad \forall g, s, t, i \quad (4.28k3)$$

$$\mu_{g,t,i,s}^{up} \geq 0, R_g^{up^{max}} - P_{g,t}^{DA} - R_{g,t,i}^{up^s} \geq 0 \quad \forall g, s, t, i \quad (4.28l1)$$

$$R_g^{up^{max}} - P_{g,t}^{DA} - R_{g,t,i}^{up^s} \leq b_{g,t,i,s}^{up} X_G^{RT} \quad \forall g, s, t, i \quad (4.28l2)$$

$$\mu_{g,t,i,s}^{up} \leq (1 - b_{g,t,i,s}^{up}) Y_G^{RT} \quad \forall g, s, t, i \quad (4.28l3)$$

$$\mu_{g,t,i,s}^{d^{max}} \geq 0, R_g^{d^{max}} - R_{g,t,i}^{down^s} \geq 0 \quad \forall g, s, t, i \quad (4.28m1)$$

$$R_g^{d^{max}} - R_{g,t,i}^{down^s} \leq b_{g,t,i,s}^{d^{max}} X_G^{RT} \quad \forall g, s, t, i \quad (4.28m2)$$

$$\mu_{g,t,i,s}^{d^{max}} \leq (1 - b_{g,t,i,s}^{d^{max}}) Y_G^{RT} \quad \forall g, s, t, i \quad (4.28m3)$$

$$\mu_{g,s,RT}^{down} \geq 0, P_{g,t}^{DA} - R_{g,t,i}^{down^s} \geq 0 \quad \forall g, s, t, i \quad (4.28n1)$$

$$P_{g,t}^{DA} - R_{g,t,i}^{down^s} \leq b_{g,s,RT}^{down} X_G^{RT} \quad \forall g, s, t, i \quad (4.28n2)$$

$$\mu_{g,s,RT}^{down} \leq (1 - b_{g,s,RT}^{down}) Y_G^{RT} \quad \forall g, s, t, i \quad (4.28n3)$$

$$\mu_{w,t,i,s}^{c^{max}} \geq 0, P_{w,t,i}^{RT^s} - P_{w,t,i}^{C^s} \geq 0 \quad \forall w, s, t, i \quad (4.28o1)$$

$$P_{w,t,i}^{RT^s} - P_{w,t,i}^{C^s} \leq b_{w,t,i,s}^{c^{max}} X_W^{RT} \quad \forall w, s, t, i \quad (4.28o2)$$

$$\mu_{w,t,i,s}^{c^{max}} \leq (1 - b_{w,t,i,s}^{c^{max}}) Y_W^{RT} \quad \forall w, s, t, i \quad (4.28o3)$$

$$\mu_{d,t,i,s}^{c^{max}} \geq 0, L_d^{max} - L_{d,t,i}^{C^s} \geq 0 \quad \forall d, s, t, i \quad (4.28p1)$$

$$L_d^{max} - L_{d,t,i}^{C^s} \leq b_{d,t,i,s}^{c^{max}} X_D^{RT} \quad \forall d, s, t, i \quad (4.28p2)$$

$$\mu_{d,t,i,s}^{c^{max}} \leq (1 - b_{d,t,i,s}^{c^{max}}) Y_D^{RT} \quad \forall d, s, t, i \quad (4.28p3)$$

$$\mu_{ev,t,i,s}^{up^{min}} \geq 0, R_{ev,t,i}^{up^s} \geq 0 \quad \forall ev, s, t, i \quad (4.28q1)$$

$$R_{ev,t,i}^{up^s} \leq b_{ev,t,i,s}^{up^{min}} X_E^{RT} \quad \forall ev, s, t, i \quad (4.28q2)$$

$$\mu_{ev,t,i,s}^{up^{min}} \leq (1 - b_{ev,t,i,s}^{up^{min}}) Y_E^{RT} \quad \forall ev, s, t, i \quad (4.28q3)$$

$$\mu_{ev,t,i,s}^{d^{min}} \geq 0, R_{ev,t,i}^{down^s} \geq 0 \quad \forall ev, s, t, i \quad (4.28r1)$$

$$R_{ev,t,i}^{down^s} \leq b_{ev,t,i,s}^{d^{min}} X_E^{RT} \quad \forall ev, s, t, i \quad (4.28r2)$$

$$\mu_{ev,t,i,s}^{d^{min}} \leq (1 - b_{ev,t,i,s}^{d^{min}}) Y_E^{RT} \quad \forall ev, s, t, i \quad (4.28r3)$$

$$\mu_{g,t,i,s}^{up^{min}} \geq 0, R_{g,t,i}^{up^s} \geq 0 \quad \forall g, s, t, i \quad (4.28s1)$$

$$R_{g,t,i}^{up^s} \leq b_{g,t,i,s}^{up^{min}} X_G^{RT} \quad \forall g, s, t, i \quad (4.28s2)$$

$$\mu_{g,t,i,s}^{up^{min}} \leq (1 - b_{g,t,i,s}^{up^{min}}) Y_G^{RT} \quad \forall g, s, t, i \quad (4.28s3)$$

$$\mu_{g,t,i,s}^{d^{min}} \geq 0, R_{g,t,i}^{down^s} \geq 0 \quad \forall g, s, t, i \quad (4.28t1)$$

$$R_{g,t,i}^{down^s} \leq b_{g,t,i,s}^{d^{min}} X_G^{RT} \quad \forall g, s, t, i \quad (4.28t2)$$

$$\mu_{g,t,i,s}^{d^{min}} \leq (1 - b_{g,t,i,s}^{d^{min}}) Y_G^{RT} \quad \forall g, s, t, i \quad (4.28t3)$$

$$\mu_{w,t,i,s}^{c^{min}} \geq 0, P_{w,t,i}^{Cs} \geq 0 \quad \forall w, s, t, i \quad (4.28x1)$$

$$P_{w,t,i}^{Cs} \leq b_{w,t,i,s}^{c^{min}} X_W^{RT} \quad \forall w, s, t, i \quad (4.28x2)$$

$$\mu_{w,t,i,s}^{c^{min}} \leq (1 - b_{w,t,i,s}^{c^{min}}) Y_W^{RT} \quad \forall w, s, t, i \quad (4.28x3)$$

$$\mu_{d,t,i,s}^{c^{min}} \geq 0, L_{d,t,i}^{Cs} \geq 0 \quad \forall d, s, t, i \quad (4.28y1)$$

$$L_{d,t,i}^{Cs} \leq b_{d,t,i,s}^{c^{min}} X_L^{RT} \quad \forall d, s, t, i \quad (4.28y2)$$

$$\mu_{d,t,i,s}^{c^{min}} \leq (1 - b_{d,t,i,s}^{c^{min}}) Y_L^{RT} \quad \forall d, s, t, i \quad (4.28y3)$$

where $X_E^{RT}, X_G^{RT}, X_W^{RT}, X_L^{RT}, Y_E^{RT}, Y_G^{RT}, Y_W^{RT}, Y_L^{RT}$ are large enough positive constants and $b_{(\cdot),t,i,s}^{(\cdot)}$ are binary variables.

3) Mixed-integer linear equivalents of the complementarity conditions section

4.3.2.3 from equation (4.29b) to (4.29c):

$$\mu_{ev,t,i,s}^{EEV^{max}} \geq 0, E_{ev,t}^{DA} - \frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Max} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{max} \geq 0 \quad \forall ev, t \quad (4.29b1)$$

$$E_{ev,t}^{DA} - \frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Max} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{max} \leq b_{ev,t,i,s}^{EEV^{max}} X_{EE} \quad \forall ev, t \quad (4.29b2)$$

$$\mu_{ev,t,i,s}^{EEV^{max}} \leq (1 - b_{ev,t,i,s}^{EEV^{max}}) Y_{EE} \quad \forall ev, t \quad (4.29b3)$$

$$\mu_{ev,t,i,s}^{EEV^{min}} \geq 0, \frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Min} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{min} - E_{ev,t}^{DA} \geq 0 \quad \forall ev, t \quad (4.29c1)$$

$$\frac{1}{N_I} \sum_s \sum_i \sum_{ev} E_{ev,t}^{Min} \cdot N_{ev,t,i}^s \cdot SOC_{EV}^{min} - E_{ev,t}^{DA} \leq b_{ev,t,i,s}^{EEV^{min}} X_{EE} \quad \forall ev, t \quad (4.29c2)$$

$$\mu_{ev,t,i,s}^{EEV^{min}} \leq (1 - b_{ev,t,i,s}^{EEV^{min}}) Y_{EE} \quad \forall ev, t \quad (4.29c3)$$

where X_{EE} and Y_{EE} are large enough positive constants and $b_{ev,t,i,s}^{EEV^{min}}$ are binary variables.

4.3.3.2 Linearization of Nonlinear terms

Nonlinear terms in $Profit^s$ can be linearized by the strong duality conditions, and KKT equalities as discussed in [21-22].

$$\begin{aligned} Profit^s = & - \sum_t \sum_g P_{g,t}^{DA} \cdot C_g - \sum_t \sum_d L_d^{max} \cdot \mu_{d,t}^{DA^{max}} \\ & + \sum_{dt} \sum_d B_{d,t}^{DA} \cdot P_{d,t}^{DA} \\ & + \frac{1}{N_I} \sum_i \sum_t \sum_g \sum_s (R_{g,t,i}^{up^s} - R_{g,t,i}^{down^s}) \cdot C_g \\ & + \frac{1}{N_I} \sum_i \sum_t \sum_d \sum_s (C_{d,t}^L \cdot L_{d,t,i}^{Cs} - L_d^{max} \cdot \mu_{d,t,i,s}^{c^{max}}) \\ & + \frac{1}{N_I} \sum_i \sum_t \sum_{ev} \sum_s (E_{ev,t,i-1}^s \\ & - (1 - N_{ev,t,i}^s) \cdot D_{ev,t,i}^s) \cdot \rho^T \end{aligned} \quad (4.33)$$

The objective function includes only one nonlinear term ($E_{ev,t,i-1}^s$) which is a bilinear one. Hence, discretising with reasonable step size is found to be a sufficiently accurate approximation as used in [24].

4.4 Case Studies and Numerical Results

To test the proposed model, the total demand is considered as 4.5GWh with five demand blocks of 2.25, 0.675, 0.675, 0.45, and 0.45 GWh. Fig. 4.4 provides demand bid prices for each period of time in five demand blocks. The system has a WGenCo with a single wind farm and two CGenCos including nuclear, and gas units which are assumed to be dispatchable. Generator data are listed in Table 4.1. The total power capacities of wind and dispatchable units are the percentages of a total installed CGenCo power capacity (P^{CGenCo}) of 5GW (see Table 4.1).

The number of intra-hour intervals is 6 (i.e. 10 min each). Figs. 4.5 and 4.6 show the intra-hourly wind power generation forecasted and EV penetration forecasted, respectively.

Table 4.1
Summary of Data

Unit Type	Nuclear	Gas
P_g^{Max} (MW)	1500	3500
C_g (\$/MWh)	12	30
$R_{g,Max}^{UP}, R_{g,Min}^{DOWN}$ (% of P_g^{Max})	0	50%
Total Demand (MW)	4500	
P^{CGenCo} (MW)	5000	
Total Wind (MW)	20% of P^{CGenCo}	

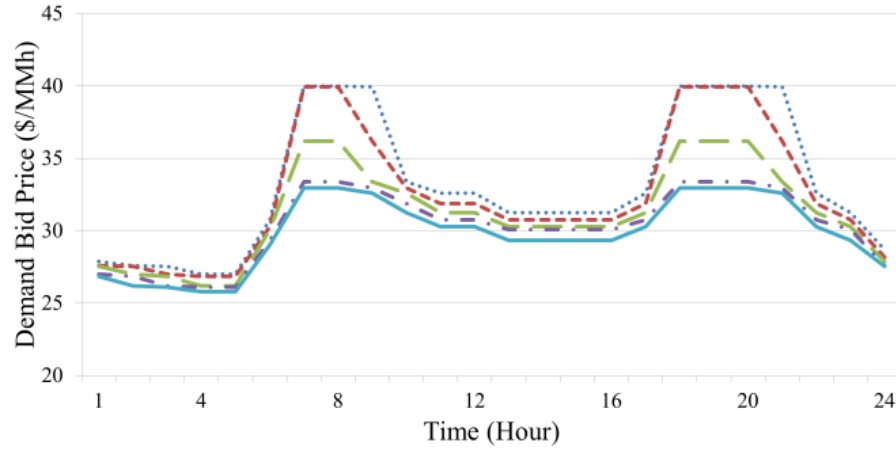


Fig. 4.4 Demand bid prices in five demand blocks

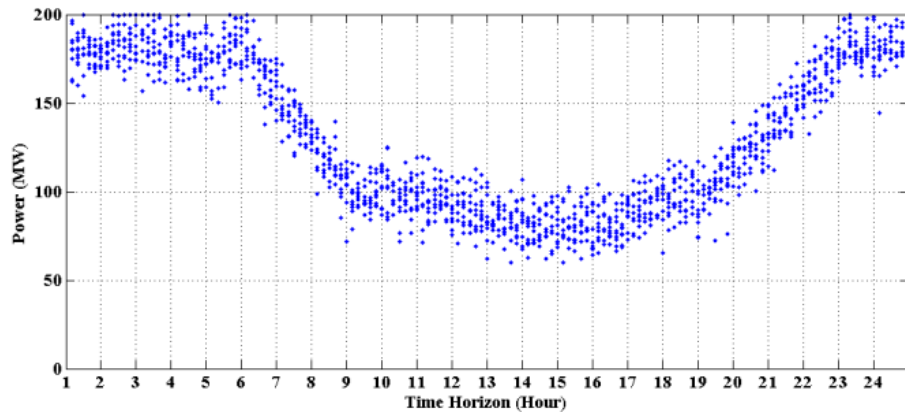


Fig. 4.5 The intra-hourly wind power generation forecasted for ten scenarios.

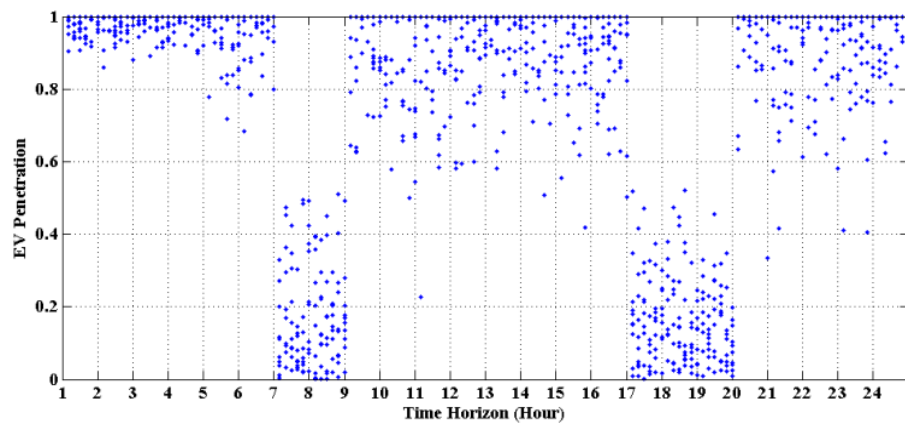


Fig. 4.6 The intra-hourly EV penetration forecasted for ten scenarios.

The maximum EV charging power is assumed to be 7.3kW, and the energy capacity of each EV is 27.4 kWh. Average annual driving distance of an EV is assumed to be 20,000 km with an average daily distance of 52.91 km. The required energy for an EV is 9 kWh/day with an average of 5.87 km/kWh [30]. We assume that the required energy for driving in one direction is the same as that of returning to the starting point. For the EV aggregator, we consider different EV numbers from one thousand to one hundred thousand. The EV fleet has its own commute time based on factors including region, city, and traffic patterns. In this chapter, the number of EV fleets is assumed to be one with commute intervals between 7 A.M. and 9 A.M., and between P.M. and 8 P.M.

The proposed model is utilized to consider endogenous tariffs. In this context, both fixed-rate and ToU tariffs and the impact of the tariffs on the wholesale-level market output are studied. In the fixed-rate tariff, the rate of charges and payments of an EV owner are considered to be fixed. Contrariwise, in ToU tariff this rate changes in different periods of the day including off-peak, peak, and base [11].

The market output in terms of the payoff, price, and generation and demand dispatch is analyzed.

4.4.1 Payoff and Price Analysis

The WGenCo profit and total payoff versus EV numbers at both fixed-rate and ToU tariffs are shown in Figs. 4.7 and 4.8 respectively. The day-ahead equilibrium prices with respect to 50,000 and 100,000 EV numbers, and using fixed-rate and ToU tariffs are shown in Figs. 4.9-4.12, respectively.

Comparing Figs. 4.9 and 4.11 shows that the increase in the EV number results in the decrease in the day-ahead equilibrium price because of the imposed

fixed-rate tariff. On the basis of this, the firm's total expected profit decreases with more EV numbers using fixed-rate tariff as shown in Fig. 4.8. However, using the ToU tariff increases the firm's expected profit with higher penetration of EVs. Comparing Figs. 4.10 and 4.12 shows that the increase in the EV number does not change the day-ahead equilibrium price because of the greater flexibility of the ToU tariff. Fig. 4.7 shows that the WGenCo's profit increases with higher penetration of EVs for two kinds of tariffs. It means that the increased EV number results in more wind energy contribution in the market.

The EV aggregator's profit is obtained through purchasing energy from the market and selling it to EV owners at a certain tariff. According to Figs. 4.10 and 4.12, using the ToU tariff reduces the difference between DA price and ToU tariffs (see Figs. 4.9—4.12), and then decreases the EV aggregator's profit in comparison with using the fixed-rate tariff (see Table 4.2).

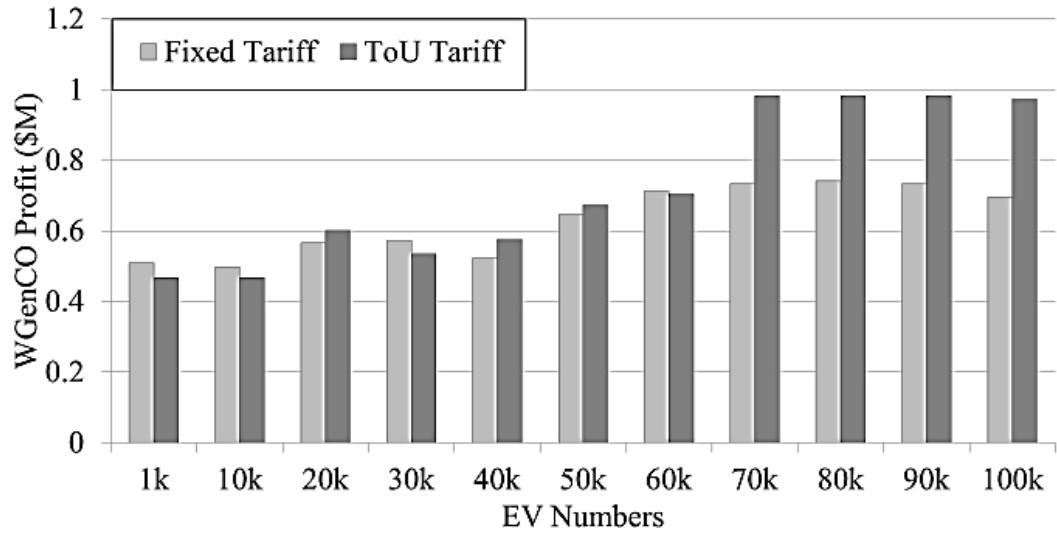


Fig. 4.7. Impact of EV numbers and tariffs on WGenCo profit

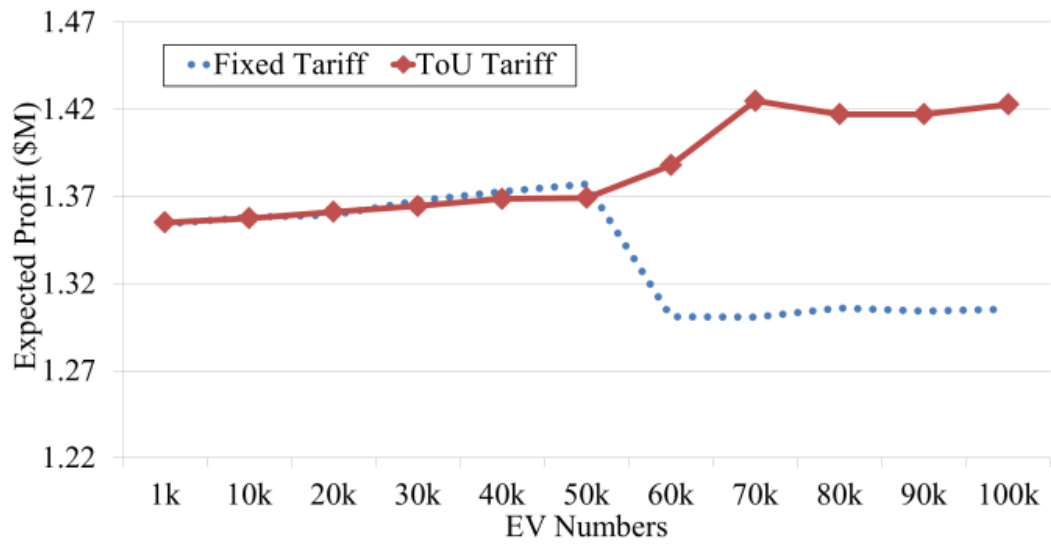


Fig. 4.8. Impact of EV numbers and tariffs on the total profit

Table 4.2
EV Aggregator's Profit

	1k EV	30k EV	50k EV	100k EV
Fixed-rate tariff	1,247	15,498	27,871	52,197
ToU tariff	463	-1,986	-742	-2,995

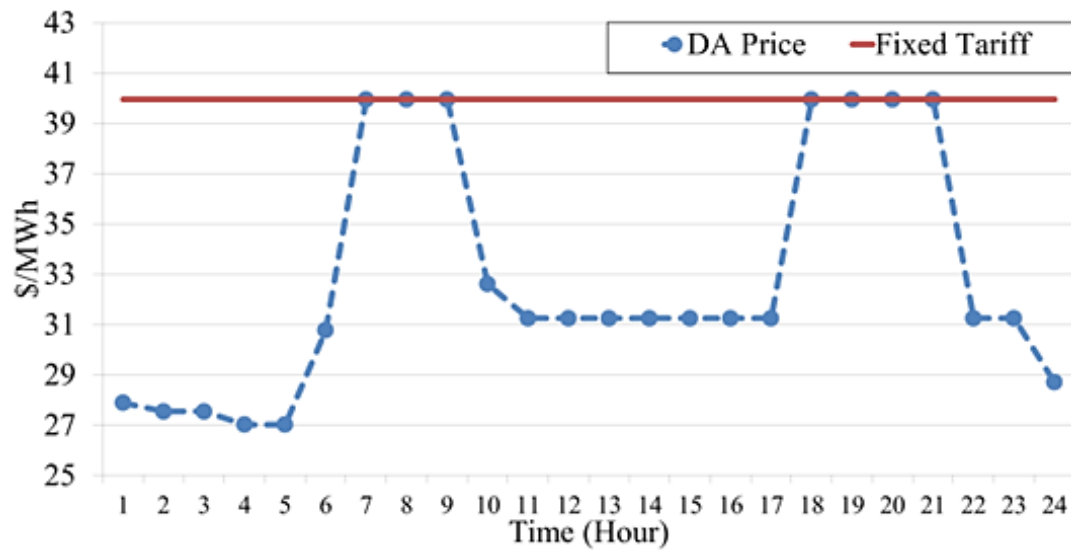


Fig. 4.9. Impact of fixed-rate tariff and 50,000 EVs on the day-ahead price

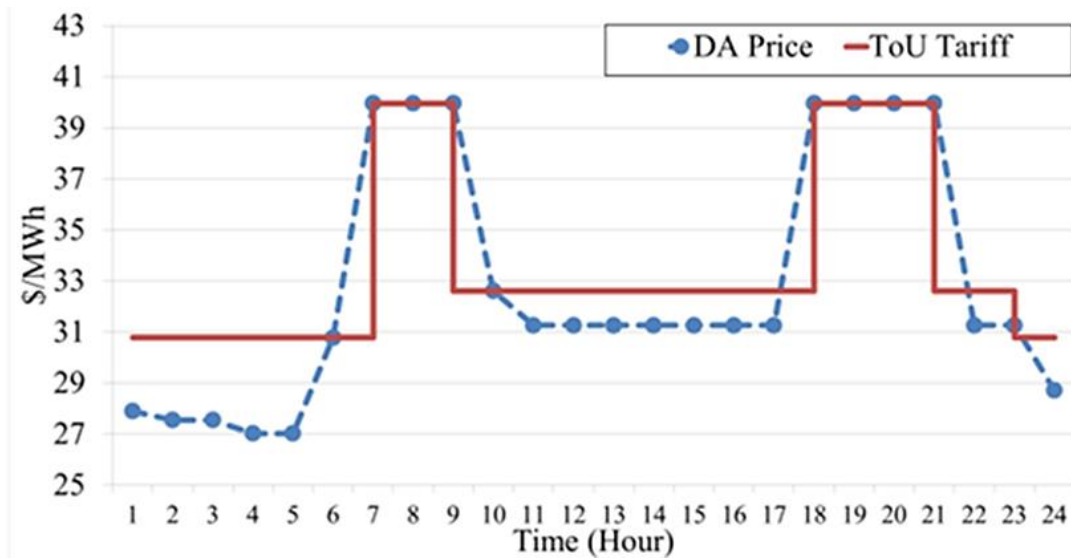


Fig. 4.10. Impact of ToU tariff and 50,000 EVs tariff on the day-ahead price

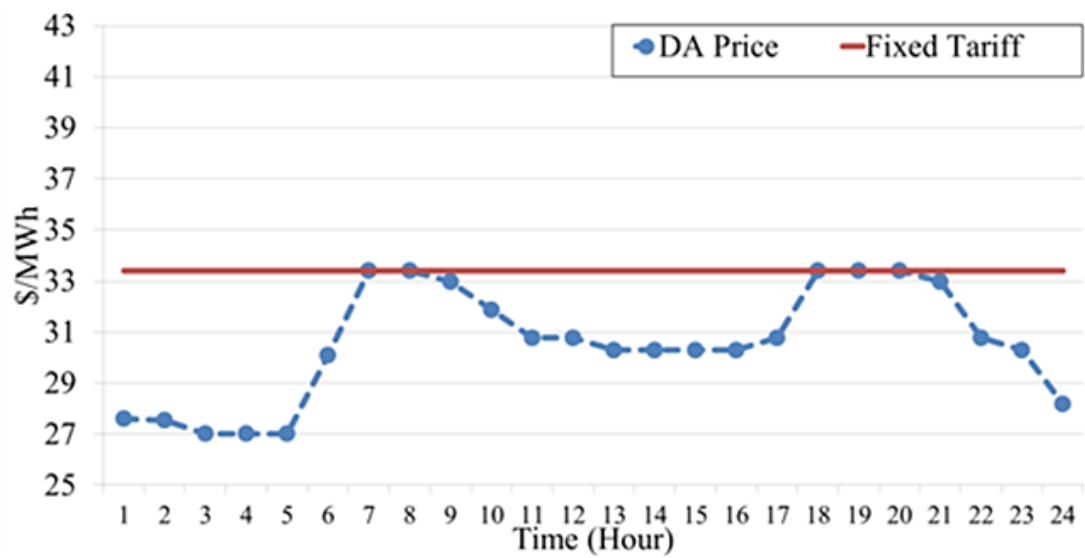


Fig. 4.11. Impact of fixed-rate tariff and 100,000 EVs on the day-ahead price

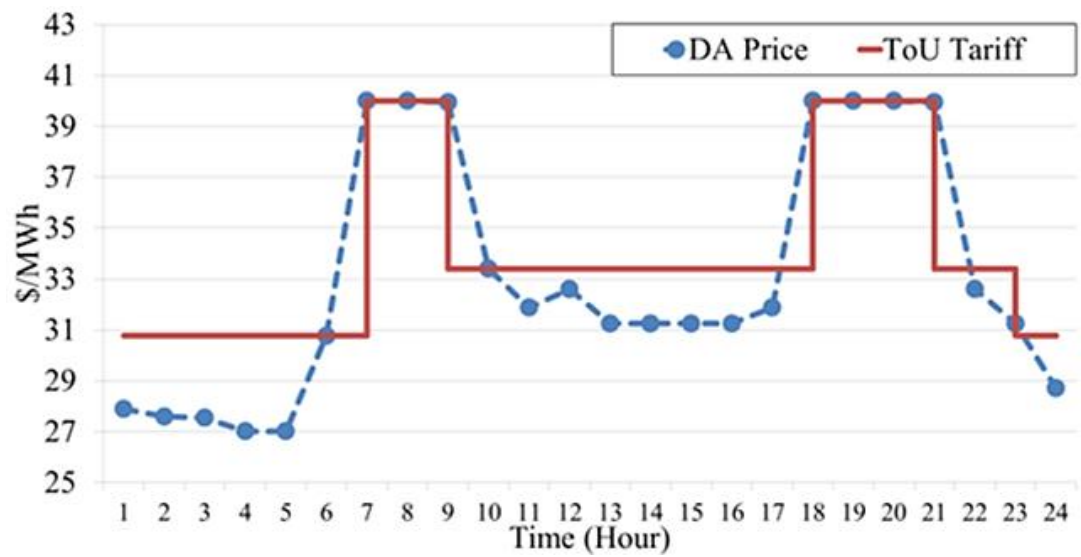


Fig. 4.12. Impact of ToU tariff and 100,000 EVs on the day-ahead price

4.4.2 Demand and Generation Dispatch Analysis

The conventional and wind power generations, and EV and load demand schedule with respect to 50,000 and 100,000 EV numbers, and fixed-rate and ToU tariffs are shown in Figs. 4.13 -4.16, respectively. As is clear from these figures, the required EV demand is supplied from the WGenCo. Therefore, it avoids shifting the emissions of the transportation sector to the electricity sector. It can be observed that the EV aggregator prefers to charge EVs during off peak between 1 A.M. to 6 A.M. Indeed, the difference between the EV tariff and the market price in these hours is high and EVs are available to be charged.

By comparing fixed-rate and ToU tariff in Fig. 4.17, it is obvious that the increase in the EV number enhances the total demand and CGenCo power because of the imposed fixed-rate tariff and less DA market price. However, using ToU tariff does not affect the total demand and CGenCo power with higher penetration of EV due to the flexibility of the ToU tariff and the consistency in the DA market price.

On the other hand, wind power penetration increases through greater numbers of EVs for two kinds of tariff as shown in Fig. 4.18. In addition, Fig. 4.19 shows the reduction in the wind curtailment with higher penetration of EVs.

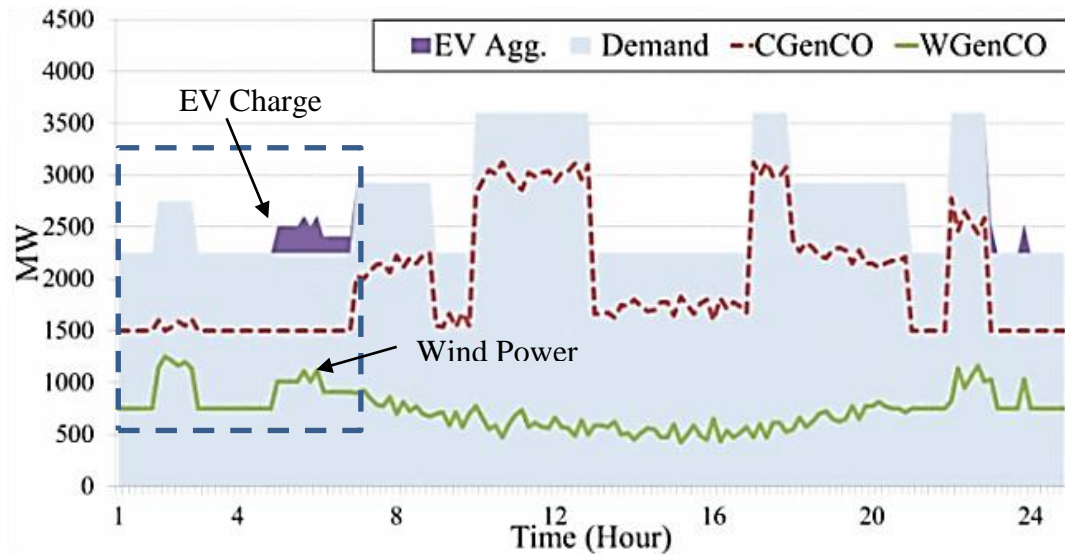


Fig. 4.13. Impact of fixed-rate tariff and 50,000 EVs on generation and demand dispatch

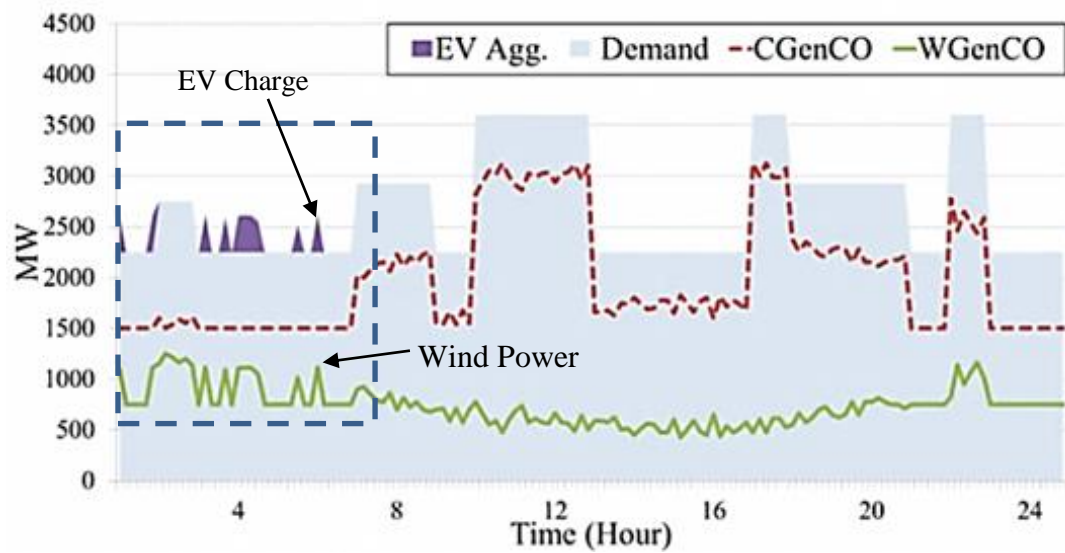


Fig. 4.14. Impact of ToU tariff and 50,000 EVs on generation and demand dispatch

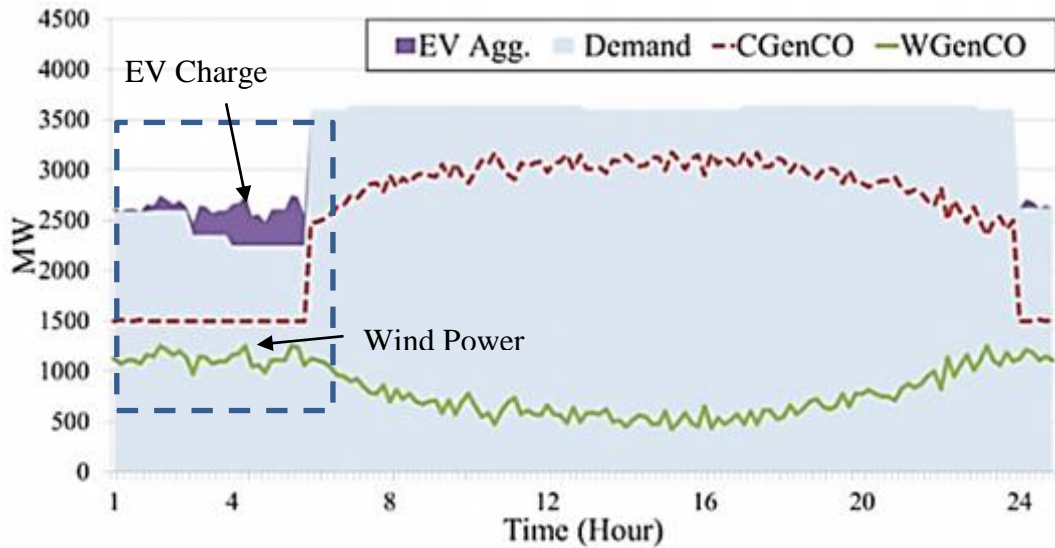


Fig. 4.15. Impact of fixed-rate tariff and 100,000 EVs on generation and demand dispatch

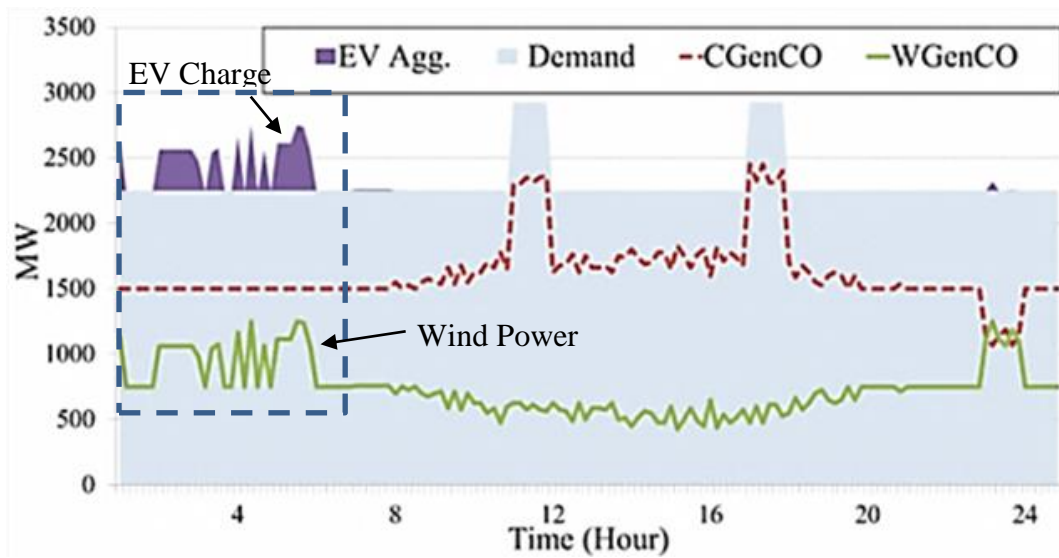


Fig. 4.16. Impact of ToU tariff and 100,000 EVs on generation and demand dispatch

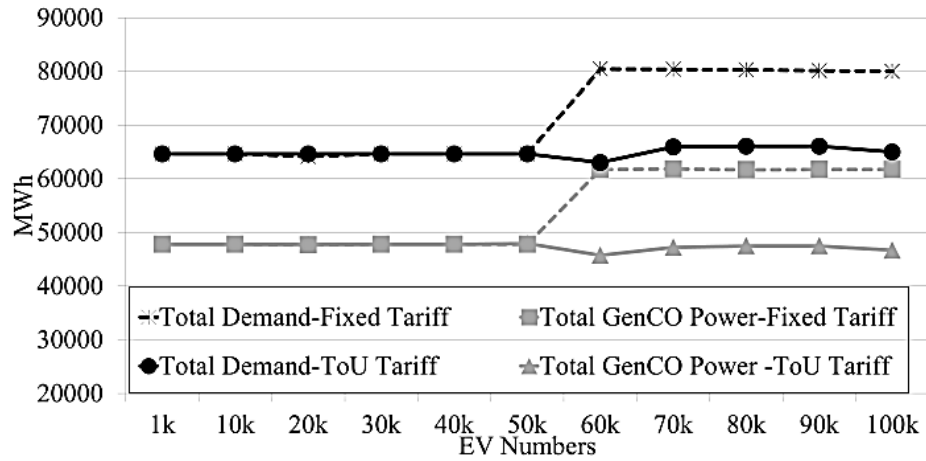


Fig. 4.17. Impact of tariffs and EV numbers on total demand and CGenCo power generation

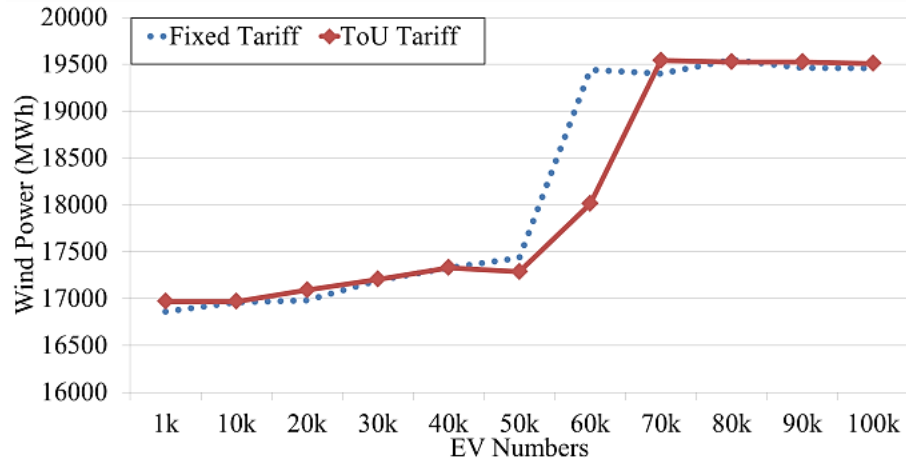


Fig. 4.18. Impact of tariffs and EV numbers on wind power generation

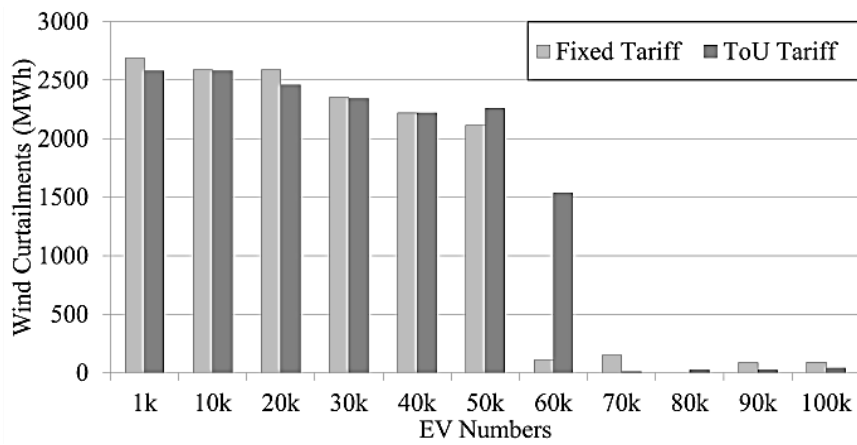


Fig. 4.19. Impact of tariffs and EV numbers on wind curtailment

4.5 Summary

In this chapter, two levels are introduced as wholesale-level and EV-level in the electricity market. At the wholesale-level, an optimal bidding/offering strategy for the EV load aggregator providing the energy and ancillary services in coordination with a strategic producer in a pool-based electricity market is modelled. At the EV-level, EV owners connect to the EV aggregator in order to take part in the market indirectly for obtaining maximum EV energy capacity and optimal charging tariff based on achieved day-ahead and real-time market data.

The proposed formulation of a stochastic intra-hour bilevel optimization problem is given by an MPEC. The MPEC includes the strategic firm's profit maximization as an upper-level problem, subject to three lower level problems: DA and RT social welfare maximizations, and the EV owners' battery energy maximization. The impact of EV numbers, and using both fixed-rate and ToU tariff on the price and market outcome are investigated. The results show that the EV-level market outputs affect the behaviour of the wholesale-level market.

Through the model, the required EV charging demand is supplied by WGenCo (wind energy) in order to reduce the emissions in transportation and electricity segments. Furthermore, high penetration of EVs leads to increasing wind power generation and reducing wind power curtailment.

The EV tariff and numbers and their trading at the EV-level can influence the market price and power generation at the wholesale-level. As the EV aggregator has to purchase energy from the wholesale-level market with uncertainty in prices and sell it to EV customers, using ToU tariffs can reduce this influence.

Chapter 5

Pool Strategy of Multiple Firms in Coordination with EV Load Aggregators

5.1 Introduction

The objective of this chapter is to develop the coordination strategy for the EV load aggregator with the CGenCos and WGenCos in multiple strategic firms competing with each other.

Similarly to Chapter 4, CGenCos, WGenCos, and EV aggregators considered in this chapter are strategic. An optimal bidding/offering strategy is developed for the EV load aggregator providing the energy and ancillary services. The optimal offering strategies are developed for CGenCos and WGenCos.

The rest of this chapter is organized as follows. Section 5.2 discusses the market framework and approach. Section 5.3 provides a formulation of a bilevel

model. Test of the proposed market model through case studies is described in Section 5.4. Finally, Section 5.5 concludes, summarizing the chapter.

5.2 Market Framework and Approach

The market frame used in this chapter is similar to one proposed in Chapter 4, in spite of multiple strategic firms. At the wholesale-level, strategic firms including CGenCos, WGenCos, and EV aggregators submit supply-offers/demand-bids to the MO to participate in the day-ahead and real-time market directly. At the EV-level, EV owners connect to each EV aggregator in order to take part in the market indirectly. EV aggregators maximize the EV energy capacities and determine optimal charging tariff based on achieved day-ahead and real-time data. Fig. 5.1 shows two levels of market framework are introduced in this chapter which are wholesale-level and EV-level for multiple strategic firms.

However, an EPEC is established to consider all strategic firms in this chapter. Similarly to Chapter 4, the upper-level problem of the bilevel model maximizes the expected profit of each strategic firm, and its lower-level problems represent different market clearing. Then, substituting the lower-level problems with their optimality conditions in the single firm model extracts an MPEC for each strategic firm. The combination of multiple firms MPEC constitutes an EPEC. The optimality conditions of the EPEC are linearized by formulating and solving a MILP problem. Finally, a diagonalization algorithm is executed to verify each solution as a real Nash equilibrium. Fig. 5.2 shows six steps to determine the market equilibria.

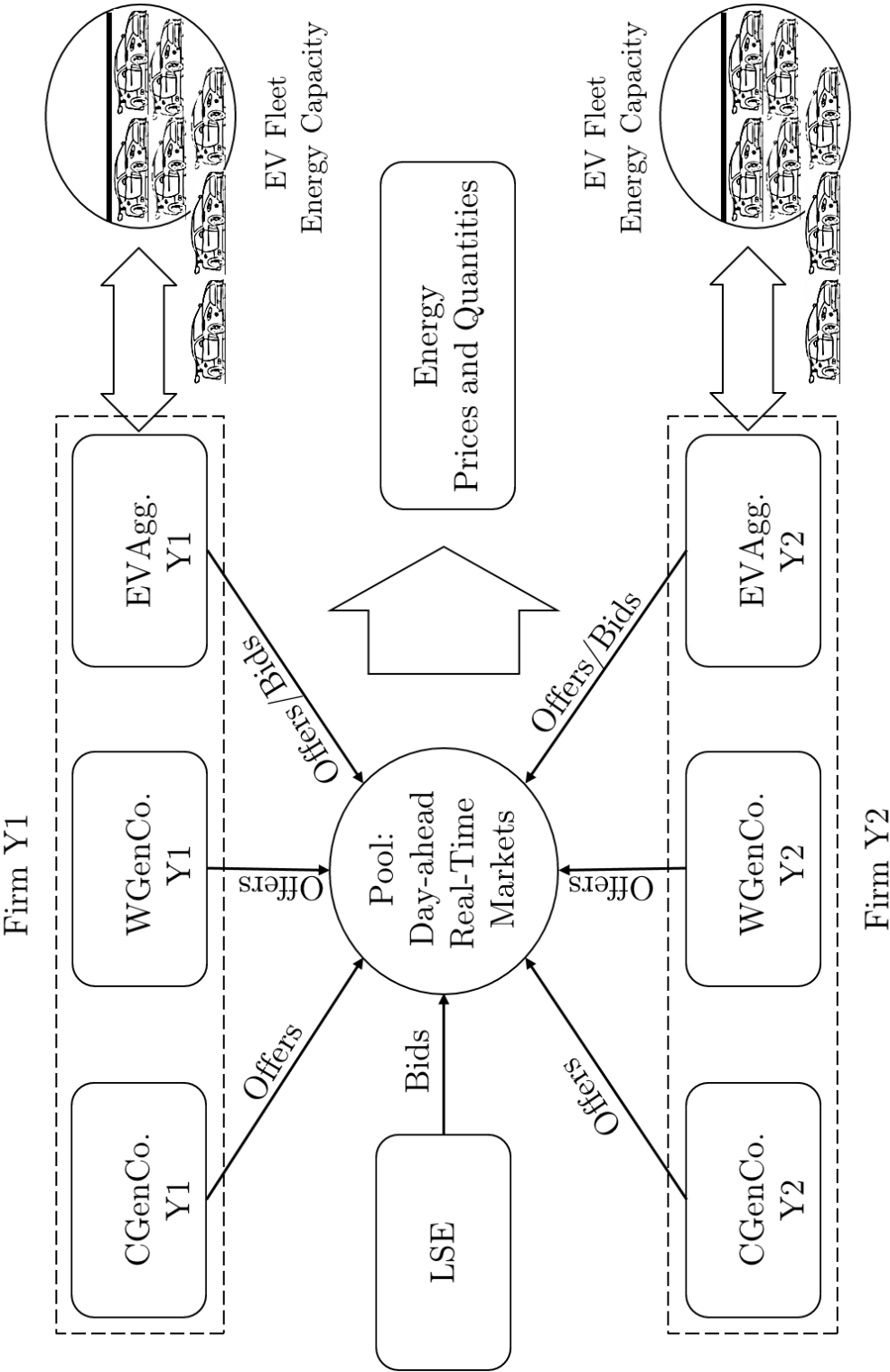


Fig. 5.1 The proposed wholesale & EV-levels structure of the electricity market for multiple strategic firms

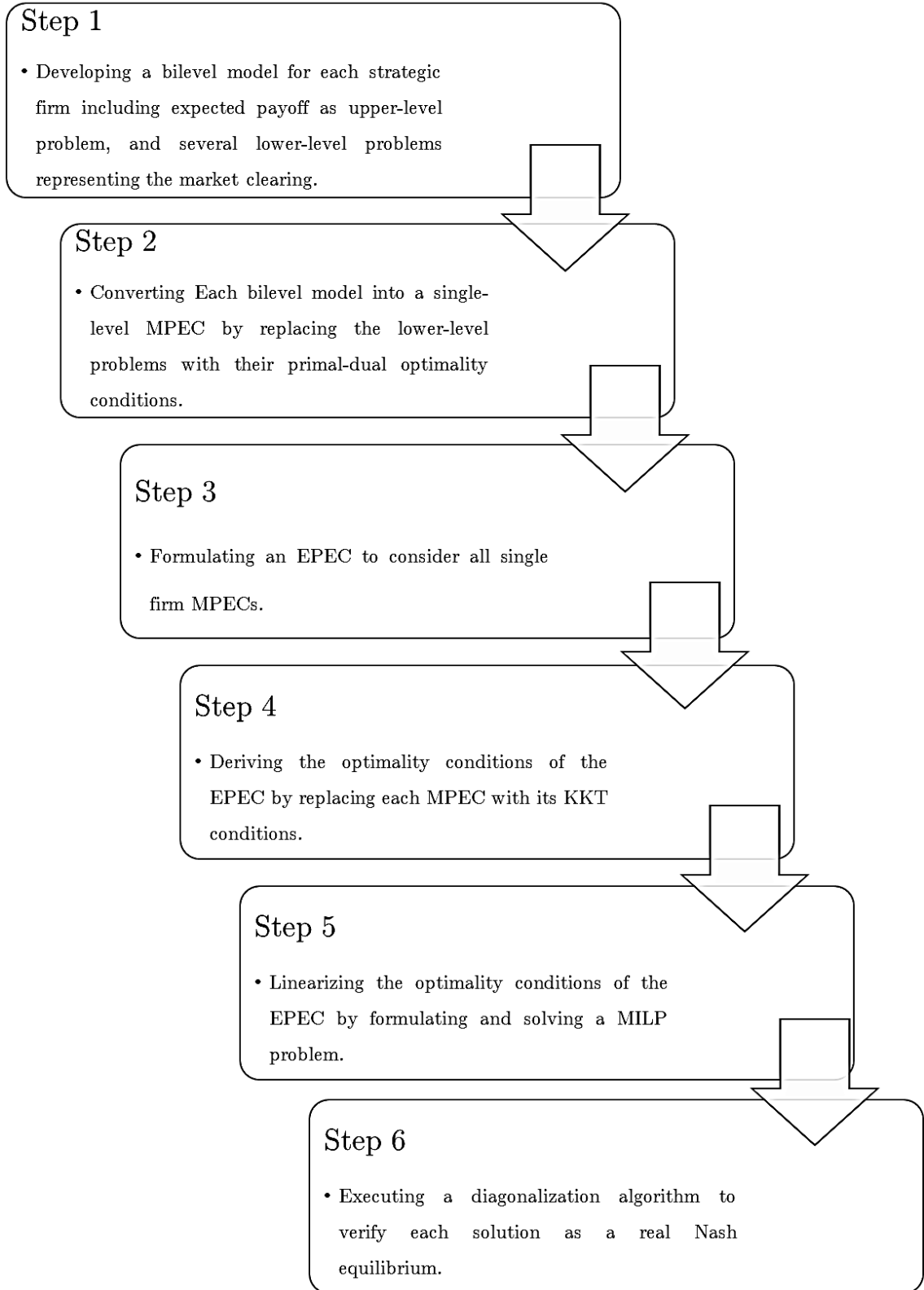


Fig. 5.2 The steps to obtain the market equilibria

5.3 Formulation of Bilevel Model

The single-period bilevel problem for each strategic firm Y is constructed and then converted into a single MPEC. Finally, the EPEC problem is formulated.

The single-period objective function (5.1a) maximizes the expected profits of each strategic firm Y which owns both CGenCos and WGenCos and constitutes unidirectional V2G services. Similar to Chapter 4 Subsections 4.3.1.1—4, three single-period lower-level problems including the day-ahead market, real-time market, and EV energy market clearing, which aim to maximize the social welfare and are subject to the power balance, and power constraints, are presented as follows:

$$\begin{aligned}
 \underset{\Omega_{prim}, \Omega_{dual}}{Max} \quad & Profit^s \\
 = & \sum_{g \in y} P_g^{DA} \cdot (\rho^{DA} - C_g) + \sum_{w \in y} P_w^{DA} \cdot \rho^{DA} \\
 & - \sum_{ev \in y} POP_{ev} \rho^{DA} - \rho^T \\
 & + \pi_s \sum_s \left(\sum_{g \in y} (R_g^{up^s} - R_g^{down^s}) (\rho_s^{RT} - C_g) \right. \\
 & - \sum_{w \in y} P_w^{DA} + P_w^{C^s} - P_w^{RT^s} \cdot \rho_s^{RT} \\
 & \left. + \sum_{ev \in y} R_{ev}^{up^s} - R_{ev}^{down^s} \rho_s^{RT} - \rho^T \right)
 \end{aligned} \tag{5.1a}$$

Subject to:

$$\alpha_g^{DA} \geq 0 \quad \forall g \in y \tag{5.1b}$$

$$\alpha_w^{DA} \geq 0 \quad \forall w \in y \tag{5.1c}$$

$$\beta_{ev}^{DA} \geq 0 \quad \forall ev \in y \tag{5.1d}$$

$$\alpha_g^{RT^s} \geq 0 \quad \forall g \in y, \forall s \tag{5.1e}$$

$$\alpha_w^{RT^s} \geq 0 \quad \forall w \in y, \forall s \tag{5.1f}$$

$$\alpha_{ev}^{RT^s} \geq 0 \quad \forall ev \in y, \forall s \quad (5.1g)$$

$$\left\{ \text{Min}_{\{\Omega_{prim}^{DA}, \Omega_{dual}^{DA}\}} \left[\begin{array}{l} \sum_g \alpha_g^{DA} P_g^{DA} + \sum_w \alpha_w^{DA} P_w^{DA} - \\ \sum_d B_d^{DA} L_d^{DA} - \sum_{ev} \beta_{ev}^{DA} POP_{ev} \end{array} \right] \right. \quad (5.2a)$$

$$\sum_g P_g^{DA} + \sum_w P_w^{DA} - \sum_d L_d^{DA} - \sum_{ev} POP_{ev} = 0 \quad : \rho^{DA} \quad (5.2b)$$

$$0 \leq POP_{ev} \leq P_{ev}^{max} \quad : \mu_{ev}^{DA^{max}}, \mu_{ev}^{DA^{min}} \quad \forall ev \quad (5.2c)$$

$$0 \leq P_g^{DA} \leq P_g^{max} \quad : \mu_g^{DA^{max}}, \mu_g^{DA^{min}} \quad \forall g \quad (5.2d)$$

$$0 \leq P_w^{DA} \leq P_w^{max} \quad : \mu_w^{DA^{max}}, \mu_w^{DA^{min}} \quad \forall w \quad (5.2e)$$

$$0 \leq L_d^{DA} \leq L_d^{max} \quad : \mu_d^{DA^{max}}, \mu_d^{DA^{min}} \quad \forall d \quad \} \quad (5.2f)$$

$$\left\{ \text{Min}_{\{\Omega_{prim}^{RT}, \Omega_{dual}^{RT}\}} \left[\begin{array}{l} \sum_g (R_g^{up^s} - R_{g,t,i}^{down^s}) \cdot \alpha_g^{RT^s} + \\ \sum_{ev} R_{ev}^{up^s} - R_{ev}^{down^s} \cdot \alpha_g^{RT^s} + \\ \sum_w (P_w^{CS} \cdot \alpha_w^{RT^s}) + \sum_d C_d^L L_d^{CS} \end{array} \right] \right. \quad (5.3a)$$

$$\sum_w P_w^{DA} + P_w^{CS} - P_w^{RT^s} - \sum_g (R_g^{up^s} - R_g^{down^s}) - \quad (5.3b)$$

$$\sum_d L_d^{CS} - \sum_{ev} R_{ev}^{up^s} - R_{ev}^{down^s} = 0 \quad : \rho_s^{RT}$$

$$0 \leq R_{ev}^{up^s} \leq R_{ev}^{up^{max}} \quad : \mu_{ev,s}^{up^{max}}, \mu_{ev,s}^{up^{min}} \quad \forall ev, s \quad (5.3c)$$

$$R_{ev}^{up^s} \leq POP_{ev} \quad : \mu_{ev,s}^{up} \quad \forall ev, s \quad (5.3d)$$

$$0 \leq R_{ev}^{down^s} \leq R_{ev}^{down^{max}} \quad : \mu_{ev,s}^{down^{max}}, \mu_{ev,s}^{down^{min}} \quad \forall ev, s \quad (5.3e)$$

$$POP_{ev} + R_{ev}^{down^s} \leq P_{ev}^{max} \quad : \mu_{ev,s}^{down} \quad \forall ev, s \quad (5.3f)$$

$$0 \leq R_g^{up^s} \leq R_g^{up^{max}} \quad : \mu_{g,s}^{up^{max}}, \mu_{g,s}^{up^{min}} \quad \forall g, s \quad (5.3g)$$

$$P_g^{DA} + R_g^{up^s} \leq R_g^{up^{max}} \quad : \mu_{ev,s}^{up} \quad \forall g, s \quad (5.3h)$$

$$0 \leq R_g^{down^s} \leq R_g^{down^{max}} \quad : \mu_{g,s}^{down^{max}}, \mu_{g,s}^{down^{min}} \quad \forall g, s \quad (5.3i)$$

$$R_g^{down^s} \leq P_g^{DA} \quad : \mu_{g,s}^{down} \quad \forall g, s \quad (5.3j)$$

$$0 \leq P_w^{CS} \leq P_w^{RT^s} \quad : \mu_{w,s}^{CS^{max}}, \mu_{w,s}^{CS^{min}} \quad \forall w, s \quad (5.3k)$$

$$0 \leq L_d^{CS} \leq L_d^{max} \quad : \mu_{d,s}^{CS^{max}}, \mu_{d,s}^{CS^{min}} \quad \forall d, s \quad \} \quad (5.3k)$$

$$\left\{ \text{Min}_{\{E_{ev}^{DA}, \Omega_{dual}^{EV}\}} \left[- \sum_{ev} \rho^{DA} E_{ev}^{DA} \right] \right. \quad (5.4a)$$

$$\sum_{ev} E_{ev}^{DA} - \sum_{ev} E_0 - 1 - N_{ev}^s \cdot D_{ev}^s \quad (5.4b)$$

$$-\sum_{ev} POP_{ev} - R_{ev}^{up^s} + R_{ev}^{down^s} = 0 \quad : \rho^T$$

$$E_{ev}^{DA} = \pi_s \sum_s \sum_i E_{ev}^s \quad \forall ev \quad (5.4c)$$

$$E_{ev}^{Min} \leq E_{ev}^{DA} \leq E_{ev}^{Max} \quad \forall ev, s \quad \} \quad (5.4d)$$

The dual variables are shown at the corresponding constraints following a colon.

5.3.1 Mathematical Program with Equilibrium Constraints

The stochastic bilevel model including multi-optimization problems transforms into a single optimization problem as a single-level stochastic MPEC as follows:

$$\begin{aligned} \min_{\Omega_{prim}, \Omega_{dual}} & -\sum_{g \in y} P_g^{DA} \cdot (\rho^{DA} - C_g) - \sum_{w \in y} P_w^{DA} \cdot \rho^{DA} + \\ & \sum_{ev \in y} POP_{ev,t} \rho^{DA} - \rho^T - \pi_s \sum_s \left(\sum_{g \in y} (R_g^{up^s} - R_g^{down^s}) (\rho_s^{RT} - \right. \\ & C_g) + \sum_{w \in y} P_w^{DA} + P_w^{Cs} - P_w^{RT^s} \cdot \rho_s^{RT} - \sum_{ev \in y} R_{ev}^{up^s} - \\ & \left. R_{ev}^{down^s} \rho_s^{RT} - \rho^T \right) \end{aligned} \quad (5.5a)$$

The lower problems are continuous linear and they can be replaced by their KKT conditions.

$$\alpha_g^{DA} \geq 0 \quad : Z\alpha_{g,j}^{DA} \quad \forall g \in y \quad (5.5b)$$

$$\alpha_w^{DA} \geq 0 \quad : Z\alpha_{w,j}^{DA} \quad \forall w \in y \quad (5.5c)$$

$$\beta_{ev}^{DA} \geq 0 \quad : Z\beta_{ev,j}^{DA} \quad \forall ev \in y \quad (5.5d)$$

$$\alpha_g^{RT^s} \geq 0 \quad : Z\alpha_{g,j}^{RT^s} \quad \forall g \in y, \forall s \quad (5.5e)$$

$$\alpha_w^{RT^s} \geq 0 \quad : Z\alpha_{w,j}^{RT^s} \quad \forall w \in y, \forall s \quad (5.5f)$$

$$\alpha_{ev}^{RT^s} \geq 0 \quad : Z\alpha_{ev,j}^{RT^s} \quad \forall ev \in y, \forall s \quad (5.5g)$$

$$\sum_g P_g^{DA} + \sum_w P_w^{DA} - \sum_d L_d^{DA} - \sum_{ev} POP_{ev} = 0 \quad : \delta_j^{DA} \quad (5.5h)$$

$$0 \leq POP_{ev} \leq P_{ev}^{max} \quad : Z_{ev,j}^{DA^{max}}, Z_{ev,j}^{DA^{min}} \quad \forall ev \quad (5.5i)$$

$$0 \leq P_g^{DA} \leq P_g^{max} \quad : Z_{g,j}^{DA^{max}}, Z_{g,j}^{DA^{min}} \quad \forall g \quad (5.5j)$$

$$0 \leq P_w^{DA} \leq P_w^{max} \quad : Z_{w,j}^{DA^{max}}, Z_{w,j}^{DA^{min}} \quad \forall w \quad (5.5k)$$

$$0 \leq L_d^{DA} \leq L_d^{max} \quad : Z_{d,j}^{DA^{max}}, Z_{d,j}^{DA^{min}} \quad \forall d \quad (5.5l)$$

$$-\beta_{ev}^{DA} + \rho^{DA} + \mu_{ev}^{DA^{max}} - \mu_{ev}^{DA^{min}} = 0 \quad : ZPOP_{ev,j} \quad \forall ev \quad (5.5m)$$

$$+\alpha_g^{DA} - \rho^{DA} + \mu_g^{DA^{max}} - \mu_g^{DA^{min}} = 0 \quad : ZP_{g,j}^{DA} \quad \forall g \quad (5.5n)$$

$$+\alpha_w^{DA} - \rho^{DA} + \mu_w^{DA^{max}} - \mu_w^{DA^{min}} = 0 \quad : ZP_{w,j}^{DA} \quad \forall w \quad (5.5o)$$

$$-B_d^{DA} + \rho^{DA} + \mu_d^{DA^{max}} - \mu_d^{DA^{min}} = 0 \quad : ZL_{d,j}^{DA} \quad \forall d \quad (5.5p)$$

$$\mu_{ev}^{DA^{min}} \geq 0, \mu_{ev}^{DA^{max}} \geq 0 \quad : X_{ev,j}^{DA^{min}}, X_{ev,j}^{DA^{max}} \quad \forall ev \quad (5.5q)$$

$$\mu_g^{DA^{min}} \geq 0, \mu_g^{DA^{max}} \geq 0 \quad : X_{g,j}^{DA^{min}}, X_{g,j}^{DA^{max}} \quad \forall g \quad (5.5r)$$

$$\mu_w^{DA^{min}} \geq 0, \mu_w^{DA^{max}} \geq 0 \quad : X_{w,j}^{DA^{min}}, X_{w,j}^{DA^{max}} \quad \forall w \quad (5.5s)$$

$$\mu_d^{DA^{min}} \geq 0, \mu_d^{DA^{max}} \geq 0 \quad : X_{d,j}^{DA^{min}}, X_{d,j}^{DA^{max}} \quad \forall d \quad (5.5t)$$

$$\begin{aligned} & \sum_g \alpha_g^{DA} P_g^{DA} + \sum_{w,t} \alpha_w^{DA} P_w^{DA} - \sum_d B_d^{DA} L_d^{DA} - \sum_{ev} \beta_{ev}^{DA} POP_{ev} \\ & \sum_{ev} \mu_{ev}^{DA^{max}} P_{ev}^{max} + \sum_g \mu_g^{DA^{max}} (P_g^{max}) + \\ & \sum_w \mu_w^{DA^{max}} (P_w^{max}) + \sum_d \mu_d^{DA^{max}} (L_d^{max}) = 0 \quad : \emptyset_j^{DA} \end{aligned} \quad (5.5u)$$

$$\begin{aligned} & \sum_w P_w^{DA} + P_w^{Cs} - P_w^{RT^s} - \sum_g (R_g^{up^s} - R_g^{down^s}) - \\ & \sum_d L_d^{Cs} - \sum_{ev} R_{ev}^{up^s} - R_{ev}^{down^s} = 0 \quad : \delta_{j,s}^{RT} \end{aligned} \quad (5.5v)$$

$$0 \leq R_{ev}^{up^s} \leq R_{ev}^{up^{max}} \quad : Z_{ev,s,j}^{up^{max}}, Z_{ev,s,j}^{up^{min}} \quad \forall ev, s \quad (5.5w)$$

$$R_{ev}^{up^s} \leq POP_{ev} \quad : Z_{ev,s,j}^{up} \quad \forall ev, s \quad (5.5x)$$

$$0 \leq R_{ev}^{down^s} \leq R_{ev}^{down^{max}} \quad : Z_{ev,s,j}^{down^{max}}, Z_{ev,s,j}^{down^{min}} \quad \forall ev, s \quad (5.5y)$$

$$POP_{ev} + R_{ev}^{down^s} \leq P_{ev}^{max} \quad : Z_{ev,s,j}^{down} \quad \forall ev, s \quad (5.5z)$$

$$0 \leq R_g^{up^s} \leq R_g^{up^{max}} \quad : Z_{g,s,j}^{up^{max}}, Z_{g,s,j}^{up^{min}} \quad \forall g, s \quad (5.6a)$$

$$P_g^{DA} + R_g^{up^s} \leq R_g^{up^{max}} \quad : Z_{g,s,j}^{up} \quad \forall g, s \quad (5.6b)$$

$$0 \leq R_g^{down^s} \leq R_g^{down^{max}} \quad : Z_{g,s,j}^{down^{max}}, Z_{g,s,j}^{down^{min}} \quad \forall g, s \quad (5.6c)$$

5.3 Formulation of Bilevel Model

$$R_g^{down^s} \leq P_g^{DA} : Z_{g,s,j}^{down} \quad \forall g, s \quad (5.6d)$$

$$0 \leq P_w^{Cs} \leq P_w^{RT^s} : Z_{w,s,j}^{c^{max}}, Z_{w,s,j}^{c^{min}} \quad \forall w, s \quad (5.6e)$$

$$0 \leq L_d^{Cs} \leq L_d^{DA} : Z_{d,s,j}^{c^{max}}, Z_{d,s,j}^{c^{min}} \quad \forall d, s \quad (5.6f)$$

$$\mu_{ev,s}^{up^{max}} - \mu_{ev,s}^{up^{min}} + \mu_{ev,s}^{up} + \alpha_{ev}^{RT^s} - \rho_s^{RT} = 0 : ZR_{ev,j}^{up^s} \quad \forall ev, s \quad (5.6g)$$

$$\mu_{ev,s}^{d^{max}} - \mu_{ev,s}^{d^{min}} + \mu_{ev,s}^{down} - \alpha_{ev}^{RT^s} + \rho_s^{RT} = 0 : ZR_{ev,j}^{d^s} \quad \forall ev, s \quad (5.6h)$$

$$\mu_{g,s}^{up^{max}} - \mu_{g,s}^{up^{min}} + \mu_{g,s}^{up} + \alpha_g^{RT^s} - \rho_s^{RT} = 0 : ZR_{g,j}^{up^s} \quad \forall g, s \quad (5.6i)$$

$$\mu_{g,s}^{d^{max}} - \mu_{g,s}^{d^{min}} + \mu_{g,s}^{down} - \alpha_g^{RT^s} + \rho_s^{RT} = 0 : ZR_{g,j}^{d^s} \quad \forall g, s \quad (5.6j)$$

$$\mu_{w,ts}^{c^{max}} - \mu_{w,ts}^{c^{min}} + \alpha_w^{RT^s} + \rho_s^{RT} = 0 : ZP_{w,j}^{Cs} \quad \forall w, s \quad (5.6k)$$

$$-\rho_s^{RT} + \mu_{d,s}^{c^{max}} - \mu_{d,s}^{c^{min}} + C_d^L = 0 : ZL_{d,j}^{Cs} \quad \forall d, s \quad (5.6l)$$

$$\mu_{ev,s}^{up^{max}} \geq 0, \mu_{ev,s}^{up^{min}} \geq 0 : X_{ev,s,j}^{up^{max}}, X_{ev,s,j}^{up^{min}} \quad \forall ev, s \quad (5.6m)$$

$$\mu_{ev,s}^{up} \geq 0, \mu_{ev,s}^{down} \geq 0 : X_{ev,s,j}^{up}, X_{ev,s,j}^{down} \quad \forall ev, s \quad (5.6n)$$

$$\mu_{ev,s}^{d^{max}} \geq 0, \mu_{ev,s}^{d^{min}} \geq 0 : X_{ev,s,j}^{d^{max}}, X_{ev,s,j}^{d^{min}} \quad \forall ev, s \quad (5.6o)$$

$$\mu_{g,s}^{up^{max}} \geq 0, \mu_{g,s}^{up^{min}} \geq 0 : X_{g,s,j}^{up^{max}}, X_{g,s,j}^{up^{min}} \quad \forall g, s \quad (5.6p)$$

$$\mu_{g,s}^{up} \geq 0, \mu_{g,s}^{down} \geq 0 : X_{g,s,j}^{up}, X_{g,s,j}^{down} \quad \forall g, s \quad (5.6q)$$

$$\mu_{g,s}^{d^{max}} \geq 0, \mu_{g,s}^{d^{min}} \geq 0 : X_{g,s,j}^{d^{max}}, X_{g,s,j}^{d^{min}} \quad \forall g, s \quad (5.6r)$$

$$\mu_{w,s}^{c^{max}} \geq 0, \mu_{w,s}^{c^{min}} \geq 0 : X_{w,s,j}^{c^{max}}, X_{w,s,j}^{c^{min}} \quad \forall w, s \quad (5.6s)$$

$$\mu_{d,s}^{c^{max}} \geq 0, \mu_{d,s}^{c^{min}} \geq 0 : X_{d,s,j}^{c^{max}}, X_{d,s,j}^{c^{min}} \quad \forall d, s \quad (5.6t)$$

$$\begin{aligned} & \sum_w P_w^{Cs} \cdot \alpha_w^{RT^s} + \sum_d C_d^L L_d^{Cs} + \sum_{ev} R_{ev}^{up^s} - R_{ev}^{down^s} \cdot \alpha_{ev}^{RT^s} + \\ & \sum_g (R_g^{up^s} - R_g^{down^s}) \cdot \alpha_g^{RT^s} - \rho_s^{RT} (\sum_w P_w^{DA} - P_w^{RT^s}) + \\ & \sum_g \mu_{g,s}^{up^{max}} (R_g^{up^{max}}) + \sum_g \mu_{g,s}^{up} (R_g^{up^{max}} - P_g^{DA}) + \end{aligned} \quad (5.6u)$$

$$\begin{aligned}
 & \sum_g \mu_{g,s}^{d^{max}} (R_g^{d^{max}}) + \sum_g \mu_{g,s}^{down} (P_g^{DA}) + \sum_{ev} \mu_{ev,s}^{up^{max}} R_{ev}^{up^{max}} + \\
 & \sum_{ev} \mu_{ev,s}^{up} POP_{ev} + \sum_{ev} R_{ev}^{d^{max}} \mu_{ev,s}^{d^{max}} + \sum_{ev} \mu_{ev,s}^d (P_{ev}^{max} - \\
 & POP_{ev,t}) + \sum_d \mu_{d,s}^{c^{max}} L_d^{DA} + \sum_w \mu_{w,s}^{c^{max}} P_w^{RT^s} = 0 \quad : \emptyset_{j,s}^{RT} \\
 & \sum_{ev} E_{ev}^{DA} - \pi_s \sum_s [\sum_{ev} E_{ev,0} - 1 - N_{ev}^s \cdot D_{ev}^s + \sum_{ev} POP_{ev} - \\
 & R_{ev}^{up^s} + R_{ev}^{down^s}] = 0 \quad : \delta_j^T \quad (5.6v) \\
 & E_{ev}^{DA} = \pi_s \sum_s \sum_i E_{ev}^s \quad \forall ev \quad (5.6w) \\
 & E_{ev}^{Min} \leq E_{ev}^{DA} \leq E_{ev}^{Max} \quad : Z_{ev,s,j}^{EEV^{max}}, Z_{ev,s,j}^{EEV^{min}} \quad \forall ev \quad (5.6x) \\
 & \rho^T - \rho^{DA} + \mu_{ev}^{EEV^{max}} - \mu_{ev}^{EEV^{min}} = 0 \quad : Z_{ev,j}^{DA} \quad \forall ev \quad (5.6y) \\
 & \mu_{ev}^{EEV^{max}} \geq 0, \mu_{ev}^{EEV^{min}} \geq 0 \quad : X_{ev,j}^{EEV^{max}}, X_{ev,j}^{EEV^{min}} \quad \forall ev \quad (5.6z) \\
 & - \sum_{ev,t} \rho^{DA} E_{ev}^{DA} + \sum_t \mu_{ev}^{EEV^{max}} E_{ev}^{Max} - \\
 & \sum_t \mu_{ev}^{EEV^{min}} E_{ev}^{Min} + \rho^T \cdot \pi_s \sum_s [\sum_{ev} E_{ev}^{DA} - \sum_{ev} E_{ev,0} + \\
 & 1 - N_{ev}^s \cdot D_{ev}^s - \sum_{ev} POP_{ev} - R_{ev}^{up^s} + R_{ev}^{down^s}] = 0 \quad : \emptyset_j^{EV} \quad (5.7a)
 \end{aligned}$$

5.3.2 Equilibrium Problem with Equilibrium Constraints

The joint solution of the MPECs of all firms (5.5a)—(5.7a) constitutes an EPEC, which is illustrated in Fig. 1.3, Chapter 1. The EPEC solution determines the market equilibria associated with their corresponding KKT conditions. The formulation is as follows:

The equality constraints of MPECs of all firms (5.5a)—(5.7d) are as follows:

$$\begin{aligned}
 & (5.5h), (5.5m)-(5.5p), (5.5u), (5.6g)-(5.6l), (5.6u), (5.6v), \\
 & (5.6w), (5.6y), (5.7a) \quad \forall j \quad (5.8)
 \end{aligned}$$

The equality constraints derived from the Lagrangian of all firms MPECs (5.5a)—(5.7a) with respect to variables are as follows:

$$\begin{aligned}
 \frac{\partial L}{\partial POP_{ev}} &= \rho^{DA} - \rho^T - \delta_j^{DA} + Z_{ev,j}^{DA^{max}} - Z_{ev,j}^{DA^{min}} - \emptyset_j^{DA} \beta_{ev}^{DA} \\
 &\quad + \sum_s \left((-Z_{ev,s,j}^{up} + Z_{ev,s,j}^{down} \right. \\
 &\quad \left. + \emptyset_{j,s}^{RT} \cdot (\mu_{ev,s}^{up} - \mu_{ev,s}^d) - \pi_s \delta_j^T + \pi_s \rho^T \emptyset_j^{EV} \right) \\
 &= 0 \quad \forall ev, j \in Y_j \quad (5.9a)
 \end{aligned}$$

$$\begin{aligned}
 \frac{\partial L}{\partial POP_{ev}} &= -\delta_j^{DA} + Z_{ev,j}^{DA^{max}} - Z_{ev,j}^{DA^{min}} - \emptyset_j^{DA} \beta_{ev}^{DA} \\
 &\quad + \sum_s \left((-Z_{ev,s,j}^{up} + Z_{ev,s,j}^{down} \right. \\
 &\quad \left. + \emptyset_{j,s}^{RT} \cdot (\mu_{ev,s}^{up} - \mu_{ev,s}^d) - \pi_s \delta_j^T + \pi_s \rho^T \emptyset_j^{EV} \right) \\
 &= 0 \quad \forall ev, j \notin Y_j \quad (5.9b)
 \end{aligned}$$

$$\begin{aligned}
 \frac{\partial L}{\partial P_g^{DA}} &= -\rho^{DA} + C_g + \delta_j^{DA} + Z_{g,j}^{DA^{max}} - Z_{g,j}^{DA^{min}} + \emptyset_j^{DA} \alpha_g^{DA} \\
 &\quad + \sum_s \left(\left(Z_{g,s,j}^{up} - Z_{g,s,j}^{down} \right. \right. \\
 &\quad \left. \left. + \emptyset_{j,s}^{RT} \cdot (\mu_{g,s}^{down} - \mu_{g,s}^{up}) \right) \right) = 0 \quad \forall g, j \in Y_j \quad (5.9c)
 \end{aligned}$$

$$\begin{aligned}
 \frac{\partial L}{\partial P_g^{DA}} &= +\delta_j^{DA} + Z_{g,j}^{DA^{max}} - Z_{g,j}^{DA^{min}} + \emptyset_j^{DA} \alpha_g^{DA} \\
 &\quad + \sum_s \left(\left(Z_{g,s,j}^{up} - Z_{g,s,j}^{down} \right. \right. \\
 &\quad \left. \left. + \emptyset_{j,s}^{RT} \cdot (\mu_{g,s}^{down} - \mu_{g,s}^{up}) \right) \right) = 0 \quad \forall g, j \notin Y_j \quad (5.9d)
 \end{aligned}$$

$$\begin{aligned}
 \frac{\partial L}{\partial P_w^{DA}} &= -\rho^{DA} + \delta_j^{DA} + Z_{w,j}^{DA^{max}} - Z_{w,j}^{DA^{min}} + \emptyset_j^{DA} \alpha_w^{DA} \\
 &\quad + \sum_s (\pi_s \cdot \rho_s^{RT} + \delta_{j,s}^{RT} + \emptyset_{j,s}^{RT} \rho_s^{RT}) = 0 \quad \forall w, j \in Y_j \quad (5.9e)
 \end{aligned}$$

$$\begin{aligned}
 \frac{\partial L}{\partial P_w^{DA}} &= +\delta_j^{DA} + Z_{w,j}^{DA^{max}} - Z_{w,j}^{DA^{min}} + \emptyset_j^{DA} \alpha_w^{DA} \\
 &\quad + \sum_s (\pi_s \cdot \rho_s^{RT} + \delta_{j,s}^{RT} + \emptyset_{j,s}^{RT} \rho_s^{RT}) = 0 \quad \forall w, j \notin Y_j \quad (5.9f)
 \end{aligned}$$

$$\begin{aligned}
 \frac{\partial L}{\partial L_d^{DA}} &= -\delta_j^{DA} + Z_{d,j}^{DA^{max}} - Z_{d,j}^{DA^{min}} - \emptyset_j^{DA} B_d^{DA} \\
 &\quad + \sum_s (\emptyset_{j,s}^{RT} \mu_{d,s}^{max} - Z_{d,s,j}^{max}) = 0 \quad \forall d, j \quad (5.9g)
 \end{aligned}$$

$$\begin{aligned} \frac{\partial L}{\partial R_{ev}^{up^s}} &= -\pi_s(\rho_s^{RT} - \rho^T) - \delta_{j,s}^{RT} + Z_{ev,s,j}^{up^{max}} - Z_{ev,s,j}^{up^{min}} + Z_{ev,s,j}^{up} \\ &\quad + \emptyset_{j,s}^{RT} \alpha_{ev}^{RT^s} + \pi_s \delta_j^T - \pi_s \rho^T \emptyset_j^{EV} = 0 \end{aligned} \quad \forall s, j, ev \in Y_j \quad (5.9h)$$

$$\begin{aligned} \frac{\partial L}{\partial R_{ev}^{up^s}} &= -\delta_{j,s}^{RT} + Z_{ev,s,j}^{up^{max}} - Z_{ev,s,j}^{up^{min}} + Z_{ev,s,j}^{up} + \emptyset_{j,s}^{RT} \alpha_{ev}^{RT^s} + \pi_s \delta_j^T \\ &\quad - \pi_s \rho^T \emptyset_j^{EV} = 0 \end{aligned} \quad \forall s, j, ev \notin Y_j \quad (5.9i)$$

$$\begin{aligned} \frac{\partial L}{\partial R_{ev}^{down^s}} &= \pi_s(\rho_s^{RT} - \rho^T) + \delta_{j,s}^{RT} + Z_{ev,s,j}^{max} - Z_{ev,s,j}^{min} + Z_{ev,s,j}^{down} \\ &\quad - \emptyset_{j,s}^{RT} \alpha_g^{RT^s} - \pi_s \delta_j^T + \pi_s \rho^T \emptyset_j^{EV} = 0 \end{aligned} \quad \forall s, j, ev \in Y_j \quad (5.9j)$$

$$\begin{aligned} \frac{\partial L}{\partial R_{ev}^{down^s}} &= +\delta_{j,s}^{RT} + Z_{ev,s,j}^{max} - Z_{ev,s,j}^{min} + Z_{ev,s,j}^{down} - \emptyset_{j,s}^{RT} \alpha_g^{RT^s} \\ &\quad - \pi_s \delta_j^T + \pi_s \rho^T \emptyset_j^{EV} = 0 \end{aligned} \quad \forall s, j, ev \notin Y_j \quad (5.9k)$$

$$\begin{aligned} \frac{\partial L}{\partial R_g^{up^s}} &= -\pi_s(\rho_s^{RT} - C_g) - \delta_{j,s}^{RT} + Z_{g,s,j}^{up^{max}} - Z_{g,s,j}^{up^{min}} + Z_{g,s,j}^{up} \\ &\quad + \emptyset_{j,s}^{RT} \alpha_g^{RT^s} = 0 \end{aligned} \quad \forall s, j, g \in Y_j \quad (5.9l)$$

$$\frac{\partial L}{\partial R_g^{up^s}} = -\delta_{j,s}^{RT} + Z_{g,s,j}^{up^{max}} - Z_{g,s,j}^{up^{min}} + Z_{g,s,j}^{up} + \emptyset_{j,s}^{RT} \alpha_g^{RT^s} = 0 \quad \forall s, j, g \notin Y_j \quad (5.9m)$$

$$\begin{aligned} \frac{\partial L}{\partial R_g^{down^s}} &= \pi_s(\rho_s^{RT} - C_g) + \delta_{j,s}^{RT} + Z_{g,s,j}^{max} - Z_{g,s,j}^{min} + Z_{g,s,j}^{down} \\ &\quad - \emptyset_{j,s}^{RT} \alpha_g^{RT^s} = 0 \end{aligned} \quad \forall s, j, g \in Y_j \quad (5.9n)$$

$$\frac{\partial L}{\partial R_g^{down^s}} = +\delta_{j,s}^{RT} + Z_{g,s,j}^{max} - Z_{g,s,j}^{min} + Z_{g,s,j}^{down} - \emptyset_{j,s}^{RT} \alpha_g^{RT^s} = 0 \quad \forall s, j, g \notin Y_j \quad (5.9o)$$

$$\frac{\partial L}{\partial L_d^{C^s}} = -\delta_{j,s}^{RT} + Z_{d,s,j}^{max} - Z_{d,s,j}^{min} + \emptyset_{j,s}^{RT} C_d^L = 0 \quad \forall s, j, d \quad (5.9p)$$

$$\frac{\partial L}{\partial P_{w,s}^{S}} = \pi_s \rho_s^{RT} + \delta_{j,s}^{RT} + Z_{w,s,j}^{max} - Z_{w,s,j}^{min} + \emptyset_{j,s}^{RT} \alpha_w^{RT^s} = 0 \quad \forall s, j, w \in Y_j \quad (5.9q)$$

$$\frac{\partial L}{\partial P_{w,s}^{S}} = +\delta_{j,s}^{RT} + Z_{w,s,j}^{max} - Z_{w,s,j}^{min} + \emptyset_{j,s}^{RT} \alpha_w^{RT^s} = 0 \quad \forall s, j, w \notin Y_j \quad (5.9r)$$

$$\frac{\partial L}{\partial \beta_{ev}^{DA}} = -Z \beta_{ev,j}^{DA} - Z POP_{ev,j} - \emptyset_j^{DA} POP_{ev} = 0 \quad \forall j, ev \in Y_j \quad (5.9s)$$

$$\frac{\partial L}{\partial \beta_{ev}^{DA}} = -ZPOP_{ev,j} - \emptyset_j^{DA} POP_{ev} = 0 \quad \forall j, ev \notin Y_j \quad (5.9t)$$

$$\frac{\partial L}{\partial \alpha_g^{DA}} = -Z\alpha_{g,j}^{DA} + ZP_{g,j}^{DA} + \emptyset_j^{DA} P_g^{DA} = 0 \quad \forall j, g \in Y_j \quad (5.9u)$$

$$\frac{\partial L}{\partial \alpha_g^{DA}} = +ZP_{g,j}^{DA} + \emptyset_j^{DA} P_g^{DA} = 0 \quad \forall j, g \notin Y_j \quad (5.9x)$$

$$\frac{\partial L}{\partial \alpha_w^{DA}} = -Z\alpha_{w,j}^{DA} + ZP_{w,j}^{DA} + \emptyset_j^{DA} P_w^{DA} = 0 \quad \forall j, w \in Y_j \quad (5.9y)$$

$$\frac{\partial L}{\partial \alpha_w^{DA}} = +ZP_{w,j}^{DA} + \emptyset_j^{DA} P_w^{DA} = 0 \quad \forall j, w \notin Y_j \quad (5.9w)$$

$$\begin{aligned} \frac{\partial L}{\partial \alpha_{ev}^{RT^s}} &= -Z\alpha_{ev,j}^{RT^s} + ZR_{ev,j}^{up^s} - ZR_{ev,j}^{d^s} + \emptyset_{j,s}^{RT} (R_{ev}^{up^s} - R_{ev}^{down^s}) \\ &= 0 \end{aligned} \quad \forall s, j, ev \in Y_j \quad (5.9z)$$

$$\frac{\partial L}{\partial \alpha_{ev}^{RT^s}} + ZR_{ev,j}^{up^s} - ZR_{ev,j}^{d^s} + \emptyset_{j,s}^{RT} (R_{ev}^{up^s} - R_{ev}^{down^s}) = 0 \quad \forall s, j, ev \notin Y_j \quad (5.10a)$$

$$\begin{aligned} \frac{\partial L}{\partial \alpha_g^{RT^s}} &= -Z\alpha_{g,j}^{RT^s} + ZR_{g,j}^{up^s} - ZR_{g,j}^{d^s} + \emptyset_{j,s}^{RT} (R_g^{up^s} - R_g^{down^s}) \\ &= 0 \end{aligned} \quad \forall s, j, g \in Y_j \quad (5.10b)$$

$$\frac{\partial L}{\partial \alpha_g^{RT^s}} = +ZR_{g,j}^{up^s} - ZR_{g,j}^{d^s} + \emptyset_{j,s}^{RT} (R_g^{up^s} - R_g^{down^s}) = 0 \quad \forall s, j, g \notin Y_j \quad (5.10c)$$

$$\frac{\partial L}{\partial \alpha_w^{RT^s}} = -Z\alpha_{w,j}^{RT^s} + ZP_{w,j}^{C^s} + \emptyset_{j,s}^{RT} P_w^{C^s} = 0 \quad \forall s, j, w \in Y_j \quad (5.10d)$$

$$\frac{\partial L}{\partial \alpha_w^{RT^s}} = +ZP_{w,j}^{C^s} + \emptyset_{j,s}^{RT} P_w^{C^s} = 0 \quad \forall s, j, w \notin Y_j \quad (5.10e)$$

$$\begin{aligned} \frac{\partial L}{\partial \rho^{DA}} &= - \sum_{g \in \Omega_j} P_g^{DA} - \sum_{w \in \Omega_j} P_w^{DA} + \sum_{ev \in \Omega_j} POP_{ev} + ZPOP_{ev,j} \\ &\quad - \sum_g ZP_{g,j}^{DA} - \sum_w ZP_{w,j}^{DA} + \sum_d ZL_{d,j}^{DA} \\ &\quad - ZE_{ev,j}^{DA} - \emptyset_j^{EV} E_{ev}^{DA} = 0 \end{aligned} \quad \forall j \quad (5.10f)$$

$$\begin{aligned}
 \frac{\partial L}{\partial \rho_s^{RT}} = & -\pi_s \cdot \sum_{g \in \Omega_j} (R_{g,s}^{up} - R_{g,s}^d) \\
 & + \pi_s \cdot \sum_{w \in \Omega_j} (P_w^{DA} + P_{w,s}^S - P_{w,s}^{RT}) + \\
 & - \pi_s \cdot \sum_{ev \in \Omega_j} (R_{ev,s}^{up} - R_{ev,s}^d) \\
 & + \sum_{ev} (ZR_{ev,j}^{d^s} - ZR_{ev,j}^{up^s}) \\
 & + \sum_g (ZR_{g,j}^{d^s} - ZR_{g,j}^{up^s}) + \sum_w ZP_{w,j}^{C^s} \\
 & - \sum_d ZL_{d,j}^{C^s} - \sum_w \emptyset_{j,s}^{RT} (P_w^{DA} - P_w^{RT^s}) = 0 \quad \forall j, s \quad (5.10g)
 \end{aligned}$$

$$\frac{\partial L}{\partial E_{ev}^{DA}} = +\delta_j^T + Z_{ev,s,j}^{EEV^{max}} - Z_{ev,s,j}^{EEV^{min}} - \emptyset_j^{EV} \rho^{DA} + \emptyset_j^{EV} \rho^T = 0 \quad \forall j, g \quad (5.10h)$$

$$\begin{aligned}
 \frac{\partial L}{\partial \rho^T} = & -POP_{ev} + R_{ev}^{up^s} - R_{ev}^{down^s} + ZE_{ev,j}^{DA} \\
 & + \emptyset_j^{EV} \pi_s \sum_s \left[\sum_{ev} E_{ev,0} - 1 - N_{ev}^s \cdot D_{ev}^s \right. \\
 & \left. + \sum_{ev} (POP_{ev} - R_{ev}^{up^s} + R_{ev}^{down^s}) \right] = 0 \quad \forall j, g \quad (5.10i)
 \end{aligned}$$

$$\frac{\partial L}{\partial \mu_{ev}^{DA^{min}}} = -ZPOP_{ev,j} - X_{ev,j}^{DA^{min}} = 0 \quad \forall j, ev \quad (5.10j)$$

$$\frac{\partial L}{\partial \mu_{ev}^{DA^{max}}} = ZPOP_{ev,j} - X_{ev,j}^{DA^{max}} + \emptyset_j^{DA} P_{ev}^{max} = 0 \quad \forall j, ev \quad (5.10k)$$

$$\frac{\partial L}{\partial \mu_{ev}^{EEV^{min}}} = -ZE_{ev,j}^{DA} - X_{ev,j}^{EEV^{min}} - \emptyset_j^{EV} E_{ev}^{Min} = 0 \quad \forall j, ev \quad (5.10l)$$

$$\frac{\partial L}{\partial \mu_{ev}^{EEV^{max}}} = ZE_{ev,j}^{DA} - X_{ev,j}^{EEV^{max}} + \emptyset_j^{EV} E_{ev}^{Max} = 0 \quad \forall j, ev \quad (5.10m)$$

$$\frac{\partial L}{\partial \mu_g^{DA^{min}}} = -ZP_{g,j}^{DA} - X_{g,j}^{DA^{min}} = 0 \quad \forall j, g \quad (5.10n)$$

$$\frac{\partial L}{\partial \mu_g^{DA^{max}}} = ZP_{g,j}^{DA} - X_{g,j}^{DA^{max}} + \emptyset_j^{DA} P_g^{max} = 0 \quad \forall j, g \quad (5.10o)$$

$$\frac{\partial L}{\partial \mu_w^{DA^{min}}} = -ZP_{w,j}^{DA} - X_{w,j}^{DA^{min}} = 0 \quad \forall j, w \quad (5.10p)$$

$$\frac{\partial L}{\partial \mu_w^{DA^{max}}} = ZP_{w,j}^{DA} - X_{w,j}^{DA^{max}} + \emptyset_j^{DA} P_w^{max} = 0 \quad \forall j, w \quad (5.10q)$$

$$\frac{\partial L}{\partial \mu_d^{DA^{min}}} = -ZL_{d,j}^{DA} - X_{d,j}^{DA^{min}} = 0 \quad \forall j, d \quad (5.10rs)$$

$$\frac{\partial L}{\partial \mu_d^{DA^{max}}} = ZL_{d,j}^{DA} - X_{d,j}^{DA^{max}} + \emptyset_j^{DA} L_d^{max} = 0 \quad \forall j, d \quad (5.10t)$$

$$\frac{\partial L}{\partial \mu_{g,s}^{up^{min}}} = -ZR_{g,j}^{up^s} - X_{g,s,j}^{up^{min}} = 0 \quad \forall j, g, s \quad (5.10u)$$

$$\frac{\partial L}{\partial \mu_{g,s}^{up^{max}}} = ZR_{g,j}^{up^s} - X_{g,s,j}^{up^{max}} + \emptyset_{j,s}^{RT} R_g^{up^{max}} = 0 \quad \forall j, g, s \quad (5.10x)$$

$$\frac{\partial L}{\partial \mu_{g,s}^{d^{min}}} = -ZR_{g,j}^{d^s} - X_{g,s,j}^{d^{min}} = 0 \quad \forall j, g, s \quad (5.10y)$$

$$\frac{\partial L}{\partial \mu_{g,s}^{d^{max}}} = ZR_{g,j}^{d^s} - X_{g,s,j}^{d^{max}} + \emptyset_{j,s}^{RT} R_g^{d^{max}} = 0 \quad \forall j, g, s \quad (5.10w)$$

$$\frac{\partial L}{\partial \mu_{g,s}^{down}} = ZR_{g,j}^{d^s} - X_{g,s,j}^{down} + \emptyset_{j,s}^{RT} P_g^{DA} = 0 \quad \forall j, g, s \quad (5.10z)$$

$$\frac{\partial L}{\partial \mu_{g,s}^{up}} = ZR_{g,j}^{up^s} - X_{g,s,j}^{up} + \emptyset_{j,s}^{RT} (P_g^{max} - P_g^{DA}) = 0 \quad \forall j, g, s \quad (5.11a)$$

$$\frac{\partial L}{\partial \mu_{ev,s}^{up^{min}}} = -ZR_{ev,j}^{up^s} - X_{ev,s,j}^{up^{min}} = 0 \quad \forall j, ev, s \quad (5.11b)$$

$$\frac{\partial L}{\partial \mu_{ev,s}^{up^{max}}} = ZR_{ev,j}^{up^s} - X_{ev,s,j}^{up^{max}} + \emptyset_{j,s}^{RT} R_{ev}^{up^{max}} = 0 \quad \forall j, ev, s \quad (5.11c)$$

$$\frac{\partial L}{\partial \mu_{g,s}^{d^{min}}} = -ZR_{ev,j}^{d^s} - X_{ev,s,j}^{d^{min}} = 0 \quad \forall j, ev, s \quad (5.11d)$$

$$\frac{\partial L}{\partial \mu_{ev,s}^{d^{max}}} = ZR_{ev,j}^{d^s} - X_{ev,s,j}^{d^{max}} + \emptyset_{j,s}^{RT} R_{gev}^{d^{max}} = 0 \quad \forall j, ev, s \quad (5.11e)$$

$$\frac{\partial L}{\partial \mu_{ev,s}^{down}} = ZR_{ev,j}^{d^s} - X_{ev,s,j}^{down} + \emptyset_{j,s}^{RT} P_{ev}^{max} - POP_{ev} = 0 \quad \forall j, ev, s \quad (5.11f)$$

$$\frac{\partial L}{\partial \mu_{ev,s}^{up}} = ZR_{ev,j}^{up^s} - X_{ev,s,j}^{up} + \emptyset_{j,s}^{RT} POP_{ev} = 0 \quad \forall j, ev, s \quad (5.11g)$$

$$\frac{\partial L}{\partial \mu_{d,s}^{cmin}} = -ZL_{d,s,j}^c - X_{w,s,j}^{cmin} = 0 \quad \forall j, d, s \quad (5.11h)$$

$$\frac{\partial L}{\partial \mu_{d,s}^{cmax}} = ZL_{d,s,j}^c - X_{w,s,j}^{cmax} + \emptyset_{j,s}^{RT} L_d = 0 \quad \forall j, d, s \quad (5.11i)$$

$$\frac{\partial L}{\partial \mu_{w,s}^{cmin}} = -ZP_{w,j}^{cs} - X_{w,s,j}^{cmin} = 0 \quad \forall j, w, s \quad (5.11j)$$

$$\frac{\partial L}{\partial \mu_{w,t,s}^{cmax}} = ZP_{w,j}^{cs} - X_{w,s,j}^{cmax} + \emptyset_{j,s}^{RT} P_w^{RT^s} = 0 \quad \forall j, w, s \quad (5.11k)$$

The complementarity conditions of all firms' MPECs (5.5a)—(5.7a) are as follows:

$$0 \leq \alpha_g^{DA} \perp Z\alpha_g^{DA} \geq 0 \quad \forall j, g \in Y_j \quad (5.12a)$$

$$0 \leq \alpha_w^{DA} \perp Z\alpha_w^{DA} \geq 0 \quad \forall j, w \in Y_j \quad (5.12b)$$

$$0 \leq \beta_{ev}^{DA} \perp Z\beta_{ev}^{DA} \geq 0 \quad \forall j, ev \in Y_j \quad (5.12c)$$

$$0 \leq \alpha_g^{RT^s} \perp Z\alpha_g^{RT^s} \geq 0 \quad \forall j, g \in Y_j, \forall s \quad (5.12d)$$

$$0 \leq \alpha_w^{RT^s} \perp Z\alpha_w^{RT^s} \geq 0 \quad \forall j, w \in Y_j, \forall s \quad (5.12e)$$

$$0 \leq \alpha_{ev}^{RT^s} \perp Z\alpha_{ev}^{RT^s} \geq 0 \quad \forall j, ev \in Y_j, \forall s \quad (5.12f)$$

$$0 \leq P_{ev}^{max} - POP_{ev} \perp Z_{ev,j}^{DA^{max}} \geq 0 \quad \forall j, ev \quad (5.12g)$$

$$0 \leq P_g^{max} - P_g^{DA} \perp Z_{g,j}^{DA^{max}} \geq 0 \quad \forall j, g \quad (5.12h)$$

$$0 \leq P_w^{max} - P_w^{DA} \perp Z_{w,j}^{DA^{max}} \geq 0 \quad \forall j, w \quad (5.12i)$$

5.3 Formulation of Bilevel Model

$$0 \leq L_d^{max} - L_d^{DA} \perp Z_{d,j}^{DA^{max}} \geq 0 \quad \forall j, d \quad (5.12j)$$

$$0 \leq POP_{ev} \perp Z_{ev,j}^{DA^{min}} \geq 0 \quad \forall j, ev \quad (5.12k)$$

$$0 \leq P_g^{DA} \perp Z_{g,j}^{DA^{min}} \geq 0 \quad \forall j, g \quad (5.12l)$$

$$0 \leq P_w^{DA} \perp Z_{w,j}^{DA^{min}} \geq 0 \quad \forall j, w \quad (5.12m)$$

$$0 \leq L_d^{DA} \perp Z_{d,j}^{DA^{min}} \geq 0 \quad \forall j, d \quad (5.12n)$$

$$0 \leq \mu_{ev}^{DA^{max}} \perp X_{ev,j}^{DA^{max}} \geq 0 \quad \forall j, ev \quad (5.12o)$$

$$0 \leq \mu_g^{DA^{max}} \perp X_{g,j}^{DA^{max}} \geq 0 \quad \forall j, g \quad (5.12p)$$

$$0 \leq \mu_w^{DA^{max}} \perp X_{w,j}^{DA^{max}} \geq 0 \quad \forall j, w \quad (5.12q)$$

$$0 \leq \mu_d^{DA^{max}} \perp X_{d,j}^{DA^{max}} \geq 0 \quad \forall j, d \quad (5.12r)$$

$$0 \leq \mu_{ev}^{DA^{min}} \perp X_{ev,j}^{DA^{min}} \geq 0 \quad \forall j, ev \quad (5.12s)$$

$$0 \leq \mu_g^{DA^{min}} \perp X_{g,j}^{DA^{min}} \geq 0 \quad \forall j, g \quad (5.12t)$$

$$0 \leq \mu_w^{DA^{min}} \perp X_{w,j}^{DA^{min}} \geq 0 \quad \forall j, w \quad (5.12u)$$

$$0 \leq \mu_d^{DA^{min}} \perp X_{d,j}^{DA^{min}} \geq 0 \quad \forall j, d \quad (5.12v)$$

$$0 \leq R_{ev}^{up^{max}} - R_{ev}^{up^s} \perp Z_{ev,s,j}^{up^{max}} \geq 0 \quad \forall j, ev, s \quad (5.12w)$$

$$0 \leq POP_{ev} - R_{ev}^{up^s} \perp Z_{ev,s,j}^{up} \geq 0 \quad \forall j, ev, s \quad (5.12x)$$

$$0 \leq R_{ev}^{d^{max}} - R_{ev}^{down^s} \perp Z_{ev,s,j}^{d^{max}} \geq 0 \quad \forall j, ev, s \quad (5.12y)$$

$$0 \leq P_{ev}^{max} - POP_{ev} - R_{ev}^{down^s} \perp Z_{ev,s,j}^{down} \geq 0 \quad \forall j, ev, s \quad (5.12z)$$

$$0 \leq R_g^{up^{max}} - R_g^{up^s} \perp Z_{g,s,j}^{up^{max}} \geq 0 \quad \forall j, g, s \quad (5.13a)$$

$$0 \leq R_g^{up^{max}} - P_g^{DA} - R_g^{up^s} \perp Z_{g,s,j}^{up} \geq 0 \quad \forall j, g, s \quad (5.13b)$$

$$0 \leq R_g^{d^{max}} - R_g^{down^s} \perp Z_{g,s,j}^{d^{max}} \geq 0 \quad \forall j, g, s \quad (5.13c)$$

$$0 \leq P_g^{DA} - R_g^{down^s} \perp Z_{g,s,j}^{down} \geq 0 \quad \forall j, g, s \quad (5.13d)$$

$$0 \leq P_w^{RT^s} - P_w^{C^s} \perp Z_{w,s,j}^{c^{max}} \geq 0 \quad \forall j, w, s \quad (5.13e)$$

$$0 \leq L_d^{max} - L_d^{C^s} \perp Z_{d,s,j}^{c^{max}} \geq 0 \quad \forall j, d, s \quad (5.13f)$$

$$0 \leq R_{ev}^{up^s} \perp Z_{ev,s,j}^{up^{min}} \geq 0 \quad \forall j, ev, s \quad (5.13g)$$

$$0 \leq R_{ev}^{down^s} \perp Z_{ev,s,j}^{d^{min}} \geq 0 \quad \forall j, ev, s \quad (5.13h)$$

$$0 \leq R_g^{up^s} \perp Z_{g,s,j}^{up^{min}} \geq 0 \quad \forall j, g, s \quad (5.13i)$$

$$0 \leq R_g^{down^s} \perp Z_{g,s,j}^{d^{min}} \geq 0 \quad \forall j, g, s \quad (5.13j)$$

$$0 \leq P_w^{C^s} \perp Z_{w,s,j}^{c^{min}} \geq 0 \quad \forall j, w, s \quad (5.13k)$$

$$0 \leq L_d^{C^s} \perp Z_{d,s,j}^{c^{min}} \geq 0 \quad \forall j, d, s \quad (5.13l)$$

$$0 \leq R_{ev}^{up^{max}} - R_{ev}^{up^s} \perp Z_{ev,s,j}^{up^{max}} \geq 0 \quad \forall j, ev, s \quad (5.13m)$$

$$0 \leq POP_{ev} - R_{ev}^{up^s} \perp Z_{ev,s,j}^{up} \geq 0 \quad \forall j, ev, s \quad (5.13n)$$

$$0 \leq R_{ev}^{d^{max}} - R_{ev}^{down^s} \perp Z_{ev,s,j}^{d^{max}} \geq 0 \quad \forall j, ev, s \quad (5.13o)$$

$$0 \leq P_{ev}^{max} - POP_{ev} - R_{ev}^{down^s} \perp Z_{ev,s,j}^{down} \geq 0 \quad \forall j, ev, s \quad (5.13p)$$

$$0 \leq \mu_{g,s}^{up^{max}} \perp X_{g,s,j}^{up^{max}} \geq 0 \quad \forall j, g, s \quad (5.13q)$$

$$0 \leq \mu_{g,s}^{up} \perp X_{g,s,j}^{up} \geq 0 \quad \forall j, g, s \quad (5.13r)$$

$$0 \leq \mu_{g,s}^{d^{max}} \perp X_{g,s,j}^{d^{max}} \geq 0 \quad \forall j, g, s \quad (5.13s)$$

$$0 \leq \mu_{g,s}^{down} \perp X_{g,s,j}^{down} \geq 0 \quad \forall j, g, s \quad (5.13t)$$

$$0 \leq \mu_{w,s}^{c^{max}} \perp X_{w,s,j}^{c^{max}} \geq 0 \quad \forall j, w, s \quad (5.13u)$$

$$0 \leq \mu_{d,s}^{c^{max}} \perp X_{d,s,j}^{c^{max}} \geq 0 \quad \forall j, d, s \quad (5.13v)$$

$$0 \leq \mu_{ev,s}^{up^{min}} \perp X_{ev,s,j}^{up^{min}} \geq 0 \quad \forall j, ev, s \quad (5.13w)$$

$$0 \leq \mu_{ev,s}^{d^{min}} \perp X_{ev,s,j}^{d^{min}} \geq 0 \quad \forall j, ev, s \quad (5.13x)$$

$$0 \leq \mu_{g,s}^{up^{min}} \perp X_{g,s,j}^{up^{min}} \geq 0 \quad \forall j, g, s \quad (5.13y)$$

$$0 \leq \mu_{g,s}^{d^{min}} \perp X_{g,s,j}^{d^{min}} \geq 0 \quad \forall j, g, s \quad (5.13z)$$

$$0 \leq \mu_{w,s}^{c^{min}} \perp X_{w,s,j}^{c^{min}} \geq 0 \quad \forall j, w, s \quad (5.14a)$$

$$0 \leq \mu_{d,s}^{c^{min}} \perp X_{d,s,j}^{c^{min}} \geq 0 \quad \forall j, d, s \quad (5.14b)$$

$$0 \leq E_{ev}^{DA} - E_{ev}^{Max} \perp Z_{ev,j}^{EEV^{max}} \geq 0 \quad \forall j, ev \quad (5.14c)$$

$$0 \leq E_{ev}^{Min} - E_{ev}^{DA} \perp Z_{ev,j}^{EEV^{min}} \geq 0 \quad \forall j, ev \quad (5.14d)$$

$$0 \leq \mu_{ev}^{EEV^{max}} \perp X_{ev,j}^{EEV^{max}} \geq 0 \quad \forall j, ev \quad (5.14e)$$

$$0 \leq \mu_{ev}^{EEV^{min}} \perp X_{ev,j}^{EEV^{min}} \geq 0 \quad \forall j, ev \quad (5.14f)$$

5.3.3 Mixed-Integer Linear Programming

The EPEC (5.8)–(5.14f) are converted to a MILP by linearizing of three nonlinearities including the nonlinear terms in the strong duality equalities, the complementarity conditions, and the nonlinear terms comprising $\emptyset_j^{EV}, \emptyset_{j,s}^{RT}$, and \emptyset_j^{DA} .

5.3.3.1 Linearization of Nonlinear Terms in the Strong Duality Equalities

Nonlinear terms in the strong duality equality (5.5u) are replaced by the complementarity conditions as follows:

$$0 \leq P_{ev}^{max} - POP_{ev} \perp \mu_{ev}^{DA^{max}} \geq 0 \quad \forall ev \quad (5.15a)$$

$$0 \leq P_g^{max} - P_g^{DA} \perp \mu_g^{DA^{max}} \geq 0 \quad \forall g \quad (5.15b)$$

$$0 \leq P_w^{max} - P_w^{DA} \perp \mu_w^{DA^{max}} \geq 0 \quad \forall w \quad (5.15c)$$

$$0 \leq L_d^{max} - L_d^{DA} \perp \mu_d^{DA^{max}} \geq 0 \quad \forall d \quad (5.15d)$$

$$0 \leq POP_{ev} \perp \mu_{ev}^{DA^{min}} \geq 0 \quad \forall ev \quad (5.15e)$$

$$0 \leq P_{g,t}^{DA} \perp \mu_g^{DA^{min}} \geq 0 \quad \forall g \quad (5.15f)$$

$$0 \leq P_w^{DA} \perp \mu_w^{DA^{min}} \geq 0 \quad \forall w \quad (5.15g)$$

$$0 \leq L_d^{DA} \perp \mu_d^{DA^{min}} \geq 0 \quad \forall d \quad (5.15h)$$

Nonlinear terms in the strong duality equality (5.6u) are replaced by the complementarity conditions as follows:

$$0 \leq R_{ev}^{up^{max}} - R_{ev}^{up^s} \perp \mu_{ev,s}^{up^{max}} \geq 0 \quad \forall ev, s \quad (5.16a)$$

$$0 \leq POP_{ev} - R_{ev}^{up^s} \perp \mu_{ev,s}^{up} \geq 0 \quad \forall ev, s \quad (5.16b)$$

$$0 \leq R_{ev}^{d^{max}} - R_{ev}^{down^s} \perp \mu_{ev,s}^{d^{max}} \geq 0 \quad \forall ev, s \quad (5.16c)$$

$$0 \leq P_{ev}^{max} - POP_{ev} - R_{ev}^{down^s} \perp \mu_{ev,s}^{down} \geq 0 \quad \forall ev, s \quad (5.16d)$$

$$0 \leq R_g^{up^{max}} - R_g^{up^s} \perp \mu_{g,s}^{up^{max}} \geq 0 \quad \forall g, s \quad (5.16e)$$

$$0 \leq R_g^{up^{max}} - P_g^{DA} - R_g^{up^s} \perp \mu_{g,s}^{up} \geq 0 \quad \forall g, s \quad (5.16f)$$

$$0 \leq R_g^{d^{max}} - R_g^{down^s} \perp \mu_{g,s}^{d^{max}} \geq 0 \quad \forall g, s \quad (5.16g)$$

$$0 \leq P_g^{DA} - R_g^{down^s} \perp \mu_{g,s}^{down} \geq 0 \quad \forall g, s \quad (5.16h)$$

$$0 \leq P_w^{RT^s} - P_w^{C^s} \perp \mu_{w,t}^{C^{max}} \geq 0 \quad \forall w, s \quad (5.16i)$$

$$0 \leq L_d^{max} - L_d^{C^s} \perp \mu_{d,s}^{C^{max}} \geq 0 \quad \forall d, s \quad (5.16g)$$

$$0 \leq R_{ev}^{up^s} \perp \mu_{ev,s}^{up^{min}} \geq 0 \quad \forall ev, s \quad (5.16k)$$

$$0 \leq R_{ev}^{down^s} \perp \mu_{ev,s}^{d^{min}} \geq 0 \quad \forall ev, s \quad (5.16l)$$

$$0 \leq R_g^{up^s} \perp \mu_{g,s}^{up^{min}} \geq 0 \quad \forall g, s \quad (5.16m)$$

$$0 \leq R_g^{down^s} \perp \mu_{g,s}^{d^{min}} \geq 0 \quad \forall g, s \quad (5.16n)$$

$$0 \leq P_w^{Cs} \perp \mu_{w,s}^{c^{min}} \geq 0 \quad \forall w, s \quad (5.16o)$$

$$0 \leq L_d^{Cs} \perp \mu_{d,s}^{c^{min}} \geq 0 \quad \forall d, s \quad (5.16p)$$

Nonlinear terms in the strong duality equality (5.7a) are replaced by the complementarity conditions as follows:

$$0 \leq E_{ev}^{DA} - E_{ev}^{Max} \perp \mu_{ev}^{EEV^{max}} \geq 0 \quad \forall ev, t \quad (5.17a)$$

$$0 \leq E_{ev}^{Min} - E_{ev}^{DA} \perp \mu_{ev}^{EEV^{min}} \geq 0 \quad \forall ev, t \quad (5.17b)$$

5.3.3.2 Linearization of Complementarity Conditions

Similar to Chapter 4, all complementarity conditions in the form of $0 \leq P \perp \mu \geq 0$ can be linearized by

$$P \geq 0, \mu \geq 0, \mu \leq b \cdot M_1, P \leq 1 - b \cdot M_2 \quad (5.18)$$

where b is an auxiliary binary variable, and M_1 and M_2 are large enough constants.

5.3.3.3 Linearization of Nonlinear Terms Comprising $\emptyset_j^{EV}, \emptyset_{j,s}^{RT}$, and \emptyset_j^{DA}

The nonlinear terms comprising $\emptyset_j^{EV}, \emptyset_{j,s}^{RT}$, and \emptyset_j^{DA} are linearized by parameterizing the KKT conditions of the EPEC. Since the set of multipliers forms a ray and some degrees of freedom, nonlinear terms are linearized by parameterizing [88].

5.3.4 Diagonalization Algorithm

Every EPEC solution is not essentially a Nash equilibrium. Based on the method proposed in [71], a one-iteration diagonalization algorithm is implemented in this thesis as shown in Fig. 5.3 to test each solution to be a real Nash equilibrium based on [91].

For the results $Q1$ and $Q2$ achieved from the EPEC problem for firms $Y1$ and $Y2$, the results $Q1$ of firm $Y1$ is fixed, and then the MPEC problem related to its rival producer $Y2$ results in $Q2^*$. If the results derived from the MPEC related to each firm are equal to the results obtained from the EPEC problem, the results $Q1$ and $Q2$ are a Nash equilibrium.

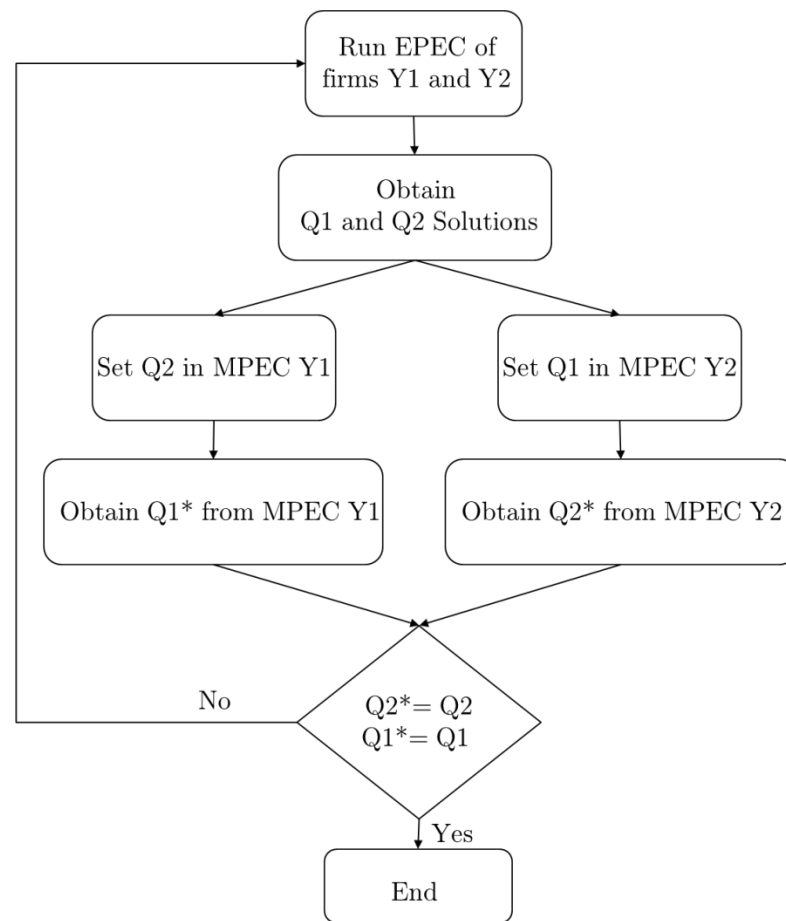


Fig. 5.3 A one-iteration diagonalization algorithm

5.4 Case Studies and Numerical Results

To test the proposed model, the total demand is considered as 3.5 GWh with two demand blocks of 2, and 1.5 GWh at the prices of \$45/MWh and \$35/MWh. The system has two WGenCo and four CGenCos including nuclear, coal, oil and gas units which are assumed to be dispatchable. Generators' data are listed in Table 5.1. The total power capacities of wind and dispatchable units are the percentages of a total installed CGenCo power capacity (P^{CGenCo}) of 3.5 GW (see Table 5.1). The system has two EV aggregators with different EV numbers. The maximum EV charging power is assumed to be 7.3 kW, and the energy capacity of each EV is 27.4 kWh. Average annual driving distance of an EV is assumed to be 20,000 km with an average daily distance of 52.91 km. The required energy for an EV is 9 kWh/day with an average of 5.87 km/kWh [35].

Table 5.1
Summary of Data

Unit Type	Nuclear	Coal	Oil	Gas
P_g^{Max} (MW)	1500	1100	500	400
Cg (\$/MWh)	12	20	25	30
$R_{g,Max}^{UP}, R_{g,Min}^{DOWN}$ (% of P_g^{Max})	0	25%	50%	50%
Total Demand (GW)	3.5			
P^{CGenCo} (GW)	3.5			
Total Wind (GW)	22% of P^{CGenCo}			

Three firms associated with different combination of units are considered in four case studies as described in Table 5.2. In addition, three different cases are

considered for EV numbers including, without EV, 50,000 and 100,000 for each EV aggregator.

We analyse the market output in terms of the payoff, price, and generation and demand dispatch. Note that there are an infinite number of Nash equilibria, whereas no firm wants to change its offering strategy. Therefore, we cannot guarantee that there are a finite or an infinite number of solutions [88].

Table 5.2

The Combination of WGenCos, CGenCos, and EV Aggregators in Three Firms

	Firm 1	Firm 2	Firm 3
Case 1	All WGenCos, CGenCos, and EV aggregators	-	-
Case 2	WGenCo1, Nuclear, and Oil units, and EV aggregator1	WGenCo2, Coal, and Gas units, and EV aggregator2	-
Case 3	All WGenCos, and CGenCos	All EV aggregators	-
Case 4	All WGenCos	All CGenCos	All EV aggregators

5.4.1 Payoff and Price Analysis

In all cases, some units offer the minimum bid price of the demands in the day-ahead market. Therefore, the day-ahead market price and EV tariff are cleared in the price of \$35/MWh. The output of the strategic firms is consistent with the outcomes of [13] and [88]. Table 5.3 demonstrate the details of the numerical results of the payoffs in different cases.

In Case 1 (or single firm), all CGenCos, WGenCos and EV aggregators are considered as a single firm. The total profit of the firm increases with more EV numbers. However, the expected profit of EV aggregators is negative. The total expected profit of the single firm in Case 1 is higher than other cases as expected.

Table 5.3
Firms' Payoff in Different Cases

		Firm 1	Firm 2	Firm 3	Total
Case 1	Without EV	\$70550	-	-	\$70550
	100,000 EV	\$72600	-	-	\$72600
	200,000 EV	\$72855	-	-	\$72855
Case 2	Without EV	\$25740	\$43550	-	\$43550
	100,000 EV	\$27575	\$44880	-	\$72455
	200,000 EV	\$27660	\$45030	-	\$72690
Case 3	Without EV	\$70550	-	-	\$70550
	100,000 EV	\$72170	\$0	-	\$72170
	200,000 EV	72170	\$0	-	\$72170
Case 4	Without EV	\$14630	\$50650	-	\$65280
	100,000 EV	\$12880	\$50650	\$1260	\$64790
	200,000 EV	\$12880	\$52398	\$2489.333	\$67767.33

In Case 2, each two firms consist of a CGenCo, a WGenCo and an EV aggregator. The total profit of each firm increases with higher EV numbers and the expected profit of EV aggregators is positive. However, the expected profit of EV aggregators is lower than dispatchable units of CGenCos.

In Case 3, EV aggregators as an individual firm are the rival of the other firm including conventional dispatchable units and WGenCos. It is observed that wind power deviations are compensated by the dispatchable units included in that firm. Therefore, the expected profit of EV aggregators is zero. Also, the results of Cases 1 and 3 for without EV are the same as expected.

In Case 4 (or three separate firms), each CGenCo, WGenCo and EV aggregator is considered as an individual firm. The EV aggregators and dispatchable units of the CGenCo compete together to provide ancillary services for wind power deviation of the WGenCos. For 200,000 EVs, the expected profit of the EV aggregator is higher than other dispatchable units of CGenCos because of the dominant regulation ancillary capacity of the EV aggregators. However, the total expected profit of all firms in Case 4 is lower than in other cases.

In summary, the coordination strategy (Cases 1 and 2) in comparison with incoordination strategy (Cases 3 and 4) is more profitable and beneficial with increasing EV penetration.

Tables C.1—C.4 demonstrate the details of the numerical results of the payoff, and prices for the four cases in Appendix C.

5.4.2 Demand and Generation Dispatch Analysis

Table 5.4 shows real-time wind power deviations and regulation up/down of the units to compensate those deviations in different scenarios for 200,000 EVs. In Case 2, the WGenCo of each firm trades with the dispatchable units owned by

that firm in the real-time market. For instance, wind power deviations in WGenCo 1 are compensated through the regulation up/down arranged by the Oil units and EV aggregator 1 into Firm 1. In Case 3, EV aggregators participate in the market as a separate firm (Firm 1) and compete with another firm including conventional dispatchable units and WGenCos. It is observed that wind power deviations are compensated by the dispatchable units included in that firm. Therefore, the EV aggregators do not contribute in regulation ancillary services. In Case 4, each CGenCo and EV aggregator compete together to allocate more share for ancillary services to compensate the real-time wind power deviations. In all cases, the regulation up is generally provided from the comparatively lower-cost units, while the regulation down is generally procured through the comparatively expensive units due to the objective function solving the EPEC.

Tables 5.5 and 5.6 demonstrate the demand curtailment and wind power curtailment in four cases for 200,000 and 100,000 EVs, respectively. The wind power curtailments are zero in all cases, since the MO maximizes social welfare in the objective function. The demand curtailment (cut-off demand) of LSE in the real-time markets is zero except in Case 4 due to three competing individual firms including EV aggregator, WGenCo, and CGenCo together.

Tables 5.7 and 5.8 show regulation-up/down power of the EV aggregators and demand curtailment in Case 4 and Case 2, respectively. In both two cases, the EV aggregators contribute more regulation ancillary services with higher EV penetration. Moreover, the demand curtailment of LSE decreases with the increase in EV numbers.

Tables C.5—C.8 demonstrate the details of the numerical results of the demand, and generation dispatch for the four cases in Appendix C.

Table 5.4

Real-time Wind Power Deviations and Regulation up/down of the Units for
200,000 EVs

	Case 1			Case 2			Case 3			Case 4		
Scenarios	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃
Wind Unit 1	+200	-20	-150	+200	-20	-150	+200	-20	-150	+200	-20	-150
Wind Unit 2	+50	-20	-100	+50	-20	-100	+50	-20	-100	+50	-20	-100
Nuclear Unit	0	0	0	0	0	0	0	0	0	0	0	0
Coal Unit	0	0	0	0	+40	+20	0	0	0	0	0	0
Oil Unit	-50	0	0	-50	+20	+40	-50	50	50	-250	-250	+250
Gas Unit	-200	35	35	-200	-20	0	-200	-10	200	-108	+200	-108
EV Agg. 1	0	5	105	0	0	+110	0	0	0	0	80.48	0
EV Agg. 2	0	0	110	0	0	+80	0	0	0	73.9	0	60.84



Firm 1



Firm 2



Firm 3

Table 5.5

Demand Curtailment and Wind Power Curtailment for 200,000 EVs

	Case 1			Case 2			Case 3			Case 4		
Scenarios	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃
Demand Curtailment	0	0	0	0	0	0	0	0	0	34.1	9.52	47.16
Wind Power Curtailment	0	0	0	0	0	0	0	0	0	0	0	0

Table 5.6

Demand Curtailment and Wind Power Curtailment for 100,000 EVs

	Case 1			Case 2			Case 3			Case 4		
Scenarios	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃
Demand Curtailment	0	0	0	0	0	0	0	0	0	163.8	36.36	181.8
Wind Power Curtailment	0	0	0	0	0	0	0	0	0	0	0	0

Table 5.7

Regulation up/down of the EV aggregators and Demand Curtailment in Case 4

	100,000 EVs			200,000 EVs		
Scenarios	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃
Demand Curtailment of LSE	163.8	36.36	181.8	34.1	9.52	47.16
Total Regulation up/down of EV Agg.	36.2	53.64	18.2	73.9	80.48	60.84

Table 5.8

Regulation up/down of the EV aggregators and Demand Curtailment in Case 2

	100,000 EVs			200,000 EVs		
Scenarios	S ₁	S ₂	S ₃	S ₁	S ₂	S ₃
Demand Curtailment of LSE	0	0	0	0	0	0
Total Regulation up/down of EV Agg.	0	0	110	0	0	190

5.5 Summary

In this chapter, the optimal bidding/offering strategy for CGenCo, WGenCo, and EV load aggregator providing the energy and ancillary services is modelled for multiple firms at wholesale-level markets. At the EV-level, EV owners connect to the EV aggregator in order to take part in the market indirectly for obtaining maximum EV energy capacity and optimal charging tariff based on achieved day-ahead and real-time market data.

Therefore, the EV aggregator as a new player competes with the conventional dispatchable units to provide the energy and ancillary services. An equilibrium approach is used to model the interactions of the strategic firms and is solved by EPEC.

Some case studies are used to validate the outcomes of the model. Moreover, impact of the increasing EV numbers in the model is investigated.

The numerical results show the effectiveness of the coordination strategy which is profitable and beneficial with increasing EV penetration in comparison with the incoordination strategy.

In other words, EV aggregators as an individual firm could not compete with other conventional dispatchable companies. Hence, merging EV aggregators in CGenCos' and WGenCos' portfolio would increase the payoff of EV aggregators and strategic firms. However, a sufficient EV number is a significant factor to affect market and EV aggregator outputs.

Chapter 6

Conclusion and Future Research

In this final chapter, a summary of the thesis is first presented. Next, a list of relevant contributions of the thesis is provided. Finally, some suggestions for future research are recommended.

6.1 Summary

This thesis focused on the impact of the participation of the EV load aggregator, and the coordination strategy on the market outcomes and prices. The coordination strategy means coordination between the EV load aggregator and generating companies through V2G technology.

In this dissertation, we addressed the two matters below:

- 1) Development of a power exchange between the EV load aggregators and WGenCos considered as price-takers in the energy and ancillary service markets (Chapter 3).

- 2) Development of a power exchange between the EV load aggregators and all generating companies considered as price-makers in the single and multiple firms (Chapters 4 and 5).

6.1.1 Coordinating EV load aggregators and WGenCos as price-takers

We developed a two-stage stochastic optimal offering/bidding strategy model for the coordinated EV-Wind units participating in the day-ahead energy, balancing, and regulation markets.

An objective function as a single optimization problem maximized the profit of coordinated WGenCo and EV aggregator associated with equality or inequality constraints.

We considered uncertainties in wind speed, energy prices, and EV owners' behavior based on driving patterns.

We investigated three different strategies including conventional systems (WGenCo without storage), WGenCo with an energy storage system, and a power system with a coordinated EV-Wind energy exchange.

The numerical results showed that the effective coordination between a WGenCo participating and an EV aggregator participating in the energy and ancillary service markets increases the WGenCo's competitiveness and mitigates wind and EV energy imbalance threats.

6.1.2 Coordinating EV load aggregators and all GenCos as price-makers

We developed a stochastic optimal bidding/offering strategy for the EV load aggregator providing the energy and ancillary services in coordination with single

and multiple strategic firms in a pool-based electricity market with endogenous formation of day-ahead and real-time prices, and EV aggregator tariff. To consider EV aggregator tariff as an endogenous variable, we defined two levels in the electricity market comprising EV-level and wholesale-level markets. At wholesale-level market, MO runs day-ahead market and real-time market clearing. At EV-level market, the EV aggregator connect to EV owners to decide maximum EV energy capacity and optimal charging tariff based on achieved day-ahead and real-time data.

We used a bilevel model to model the behaviour of proposed markets. A bilevel problem includes an upper-level problem and a set of lower-level problems which are limited by the upper and lower equality and inequality constraints. The upper-level problem represents the strategic firm's profit maximization. The lower-level problems include the day-ahead market, real-time market, and EV energy market clearing which aim to maximize the social welfare and are subject to the power balance, and power limits.

We studied single and multiple strategic firms in the proposed markets. For single firm, a bilevel model including multi-optimization problems converts into a single optimization problem as a single-level stochastic MPEC. For multiple firms, multiple stochastic MPECs constitute an EPEC. Finally, all single and multiple firms' problems are linearized by formulating and solving an MILP problem.

The numerical results showed the effectiveness of the coordination strategy, which is profitable and beneficial with increasing EV penetration in comparison with the incoordination strategy. We concluded that EV aggregators as an individual firm could not compete with other conventional, dispatchable companies. Hence, merging EV aggregators in CGenCos' and WGenCos' portfolio would increase the payoff of EV aggregators and strategic firms. However, a

sufficient EV number is a significant factor to affect market and EV aggregator outputs.

Moreover, the numerical results showed that the EV tariff and numbers at EV-level can influence the market price and power generation at wholesale-level in the electricity market. In addition, the high penetration of EVs leads to increasing the wind power penetration and reducing the wind power curtailment.

6.2 Main Contributions

The main contributions of the thesis work which have been declared in the introduction of each chapter are classified here in more solid expressions as follows:

1. For the coordinated EV-Wind and the ESS-Wind, developing a two-stage SLP-based optimal offering/bidding strategy model in the day-ahead energy, balancing, and regulation markets.
2. Comprehensive comparisons of three strategies including the coordinated EV-Wind, the ESS-Wind, and conventional systems (WGenCo without energy storage).
3. For the single and multiple firms including the coordinated EV aggregator, CGenCos and WGenCos, developing an optimal bidding/offering strategy model in a pool-based electricity market with endogenous formation of day-ahead and real-time prices, and EV aggregator tariff.
4. Defining EV-level and wholesale-level in the electricity market to consider impact of EV aggregator tariff on the price and market outputs.
5. Proposing formulation of a stochastic bilevel optimization problem including an upper-level problem and three lower-level problems for the

sake of a) the strategic firm's profit maximization, and b) day-ahead and real-time social welfare maximization, and c) EV owner's battery energy maximization, respectively.

6. Comprehensive comparisons of different case studies including a) coordination and incoordination strategies; b) with and without EVs; c) the impact of different EV numbers; d) fixed-rate and ToU tariff; e) single and multiple firms.
7. Considering the uncertainties associated with wind forecast, energy price, and EV owners' behavior based on driving patterns.

6.3 Recommendations for Future Research

The concept of V2G in the electricity market is indeed a new and interesting research area to design the future structure and architecture of the electricity market. This concluding section proposes some relevant areas for future research as follows:

1. Considering risk-constrained profit-maximization of a strategic firm such as conditional value at risk, (CVaR) to investigate the impact of risk aversion on market decisions.
2. Considering the strategic LSEs through their demand function bids to award more flexibility for normal consumers as active players.
3. Integrating transmission networks and security constraints including a set of plausible contingencies, i.e., generators and transmission line outages into the market clearing problems.

4. Investigating the impact of subsidizing renewable energies and EVs policies on the economics of CGenCos and the electricity market.
5. Studying the impact of the proposed market considered in this thesis on other markets such as futures market, and gas and oil markets.
6. Comparing a robust model with a stochastic programming model considered in the thesis work.
7. Developing an analytical sensitivity analysis tool to evaluate the effect of the diverse parameters on the market outputs.

Appendix A

Scenario Generation and Reduction Techniques

There are several different scenario generation and reduction techniques for stochastic programming [59]. The Monte Carlo simulations are applied to generate scenarios in [59]. In [60], the time series models are used to generate scenarios for prices in electricity markets. The most common scenario-reduction technique is based on Kantorovich distance [61]. In [62], a scenario generation for price forecasting is based on the roulette wheel mechanism. In this thesis, scenario generation and reduction techniques are used for simulating wind speed, energy price, and the number of EVs engaged as follows.

A.1 Wind and Energy Price Scenarios

Wind speed forecasting for the next day can be obtained from numerical meteorological programs, however, forecasts are never perfect. The ARMA model

is used to simulate wind speed forecast errors [63-64,57]. The ARMA (p, q) model for a stochastic process X is defined as:

$$x(t) = \sum_{j=1}^p \alpha(j) \cdot x(t-j) + z(t) + \sum_{j=1}^q \beta(j) \cdot z(t-j) \quad (\text{A.1})$$

where p is autoregressive parameters $\alpha_1, \alpha_2, \dots, \alpha_p$, and q is moving average parameters $\beta_1, \beta_2, \dots, \beta_q$; $Z(t)$ is a random Gaussian variable with standard deviation σ [57].

The estimation and adjustment of ARMA models have been investigated in literature. In this thesis, the first order of the ARMA model, ARMA (1,1), is used to simulate wind speed forecasting errors. This approach has been suggested in [64], [57]:

$$\Delta V(t) = \alpha \Delta V(t-1) + Z(t) + \beta Z(t-1) \quad (\text{A.2})$$

where $\Delta V(t)$ is the wind speed forecast error at the time (t) forecast; and α , and β are parameters.

The estimation of parameters and β for a given wind speed forecast is done as suggested in [63]. ARMA parameters are obtained by minimizing the difference in the root mean square error between the simulated ARMA model and the wind speed measurement data [64], [101].

The real wind speed $V(t)$ is calculated as the sum of the wind speed forecast $V^f(t)$ and the wind speed forecast error:

$$V(t) = V^f(t) + \Delta V \quad t \quad (A.3)$$

Once a large number of scenarios are generated, the wind speed scenarios are transformed into power scenarios through the power conversion curve for each wind turbine [12], [65].

In addition, the process of scenario generation using the ARMA (1,1) model is as follows [57].

Step 1: Initialize the scenario counter: $s \leftarrow 0$.

Step 2: Update the scenario counter and initialize the time period counter: $s \leftarrow s + 1$, $t \leftarrow 0$.

Step 3: Update the time period counter: $t \leftarrow t + 1$.

Step 4: Randomly generate $Z_t \sim N(0, \sigma)$.

Step 5: Evaluate $\Delta V \quad t^s$.

Step 6: If $t < NT$ go to Step 3), otherwise go to Step 7)

Step 7: If $\omega < N$ go to Step 2), otherwise the scenario-generation process concludes.

Similarly, ARIMA models have been applied to forecast electricity prices, which appear non-stationary when the processes present a periodic or seasonal pattern [57], [102].

A.2 EV Number Scenarios

Any driving profile has a commute time including morning and evening with the start and end times, and a commute distance. Major commuting would normally begin between 7 AM and 9 AM to go to work and between 5 PM and 8 PM to come

back from work. For all other times, the EVs are assumed to be available to be plugged into the electricity grid [66].

The EV availability at each interval has associated unplanned departure and arrival probabilities. The number of EVs is considered to be random, and Monte Carlo simulations are used to generate possible scenarios.

The total number of EVs is 1p.u. It is assumed that on average, from 2 AM to 5 AM, 98% of EVs are plugged-in with a standard deviation of 5%. For commute periods, on average, 20% of EVs are plugged-in with a standard deviation of 10%, and during other periods it is assumed that 85% of EVs are plugged-in with a standard deviation of 20% [9]. The availability of EVs in various time periods is shown in Table A.1.

Table A.1

The Availability of EVs in Various Time Intervals						
Hour	2:00	5:00	7:00	9:00	17:00	20:00
	5:00	7:00	9:00	17:00	20:00	2:00
St.dev (%)	5	20	10	20	10	20
Mean (pu)	0.98	0.85	0.20	0.85	0.20	0.85

A.3 Scenario Reduction

In stochastic optimization problems with various inherent uncertainties, a large number of scenarios can emerge. It can, therefore, be computationally expensive. Therefore, a technique for reducing the number of scenarios is required.

In this paper, the scenario reduction algorithm is based on [67], [68]. The basic idea of the scenario reduction is to eliminate scenarios with low-probabilities, and cluster similar scenarios [69], [101]. The new probability of a preserved scenario is

determined as the sum of its initial probability and the probabilities of similar scenarios that have been eliminated. We used SCENRED as a tool for scenario reduction [69]. SCENRED contains three reduction algorithms: the fast backward method, a mix of fast backward/forward methods and a mix of fast backward/backward methods. The algorithms have different computational performances, and the choice of algorithms for a certain problem depends on the size of the problem and the required solution accuracy. The strategy used in [67-69] recommends that the optimal deletion of scenarios should be determined by a conceptual algorithm called backward reduction. If the number of preserved scenarios is small (strong reduction), the optimal selection of a single scenario may be repeated recursively until a prescribed number of preserved scenarios is selected. This strategy provides the basic concept of the conceptual algorithm called forward selection. In this paper, the fast backward/forward method is selected to reduce the number of scenarios [68].

The uncertainties characterizing the stochastic data are modeled through a symmetric scenario tree [65]. Each branch of the scenario tree includes three nodes: the day-ahead energy price, wind power outputs, and EV penetration. The scenario tree generation process is described as follows:

Step 1: Generate a set of 10,000 day-ahead price scenarios (A_s^p).

Step 2: Generate a set of 10,000 wind power scenarios (A_s^w) for each of the day-ahead price scenarios.

Step 3: Generate a set of 10,000 EV number scenarios (A_s^{ev}) for each of the wind power scenarios.

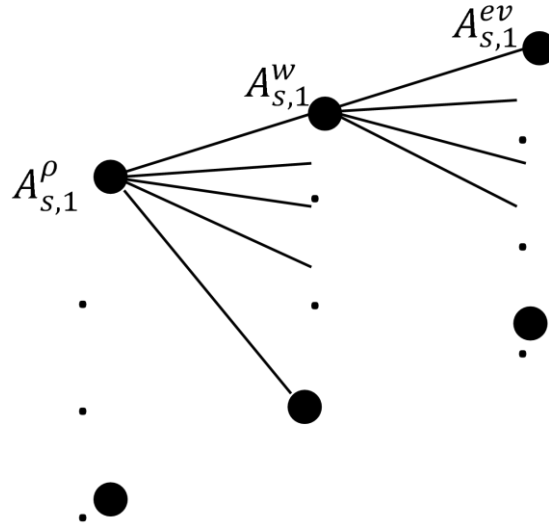


Fig. A.1 A path through the tree is called a scenario and consists of realizations of all random variables.

The total number of scenarios making the tree is $A_s = A_s^\rho \times A_s^w \times A_s^{ev} = 10^{12}$, which makes the size of the tree too large for the optimization problem to be tractable. Therefore, a reduction technique proposed in [69] is used to reduce the number of A_s^ρ , A_s^w , and A_s^{ev} to 10 each, i.e., the reduced tree consists of 10^3 scenarios [65].

Appendix B

Absolute Value of the Variable in the MILP

To represent the absolute value of variable x in a linear form for MILP formulation, the following equations are used:

$$0 \leq |x| - x \leq M a_{s,t,i}^{\Delta} \quad (\text{B.1})$$

$$0 \leq |x| + x \leq M [1 - a_{s,t,i}^{\Delta}] \quad (\text{B.2})$$

$a_{s,t,i}^{\Delta} \in \{0,1\}$, M is a large positive number

For $\Delta > 0$:

$$\text{if } a_{s,t,i}^{\Delta} = 1 \rightarrow \begin{cases} 0 \leq |x| - x \leq M \\ |x| = -x \end{cases}, \text{impossible} \quad (\text{B.3})$$

$$\text{if } a_{s,t,i}^{\Delta} = 0 \rightarrow \begin{cases} |x| = x \\ 0 \leq |x| + x \leq M \end{cases}, \text{ possible} \quad (\text{B.4})$$

For $x < 0$:

$$\text{if } a_{s,t,i}^{\Delta} = 1 \rightarrow \begin{cases} 0 \leq |x| - x \leq M \\ |x| = -x \end{cases}, \text{ possible} \quad (\text{B.5})$$

$$\text{if } a_{s,t,i}^{\Delta} = 0 \rightarrow \begin{cases} |x| = x \\ 0 \leq |x| + x \leq M \end{cases}, \text{ impossible} \quad (\text{B.6})$$

Appendix C

Additional Data

This section includes the additional data on the multiple firms in coordination with EV load aggregators (chapter 5) to discuss the payoff and price, and demand and generation dispatch analysis for case studies 1-4 (Section 5.4). In Case 1 (or single firm), all CGenCos, WGenCos and EV aggregators are considered as a single firm. In Case 2, each two firms consist of a CGenCo, a WGenCo and an EV aggregator. In Case 3, EV aggregators as an individual firm are the rival of the other firm including conventional dispatchable units and WGenCos. In Case 4 (or three separate firms), each CGenCo, WGenCo and EV aggregator is considered as an individual firm.

Tables C.1—C.4 demonstrate the details of the numerical results of the payoff, and prices for the four cases.

Tables C.5—C.8 demonstrate the details of the numerical results of the demand, and generation dispatch for the four cases.

Table C.1
The Results of Profit and Prices for Case 1

		Without EV			100,000 EVs			200,000 EVs		
Prices	DA Market Price (\$/MWh)	35			35			35		
	EV Tariff (\$/MWh)	-			35			35		
	RT Market Prices (\$/MWh)	70	70	0	0	0	70	70	0	0
Profits	Total Profit (\$)	70550			72600			72855		
	Total Profit of Firm 1 (\$)	70550			72600			72855		
	Total Profit of Firm 2 (\$)	-			-			-		
	Total Profit of Firm 3 (\$)	-			-			-		
Wind Unit Y1	Expected Profit (\$)	12740			6300			13300		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	70	0	0
Wind Unit Y1	Expected Profit (\$)	7140			4200			7700		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	70	0	0
Nuclear Unit Y1	Expected Profit (\$)	34500			34500			34500		
	DA Offer Price (\$/MWh)	35			0			0		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	70	0	0
Coal Unit Y1	Expected Profit (\$)	16500			16118.5			16500		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	70	0	0	0	70	70	0	0
Oil Unit Y1	Expected Profit (\$)	2520			3250			4550		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	70	0	0	0	70	70	0	0
Gas Unit Y1	Expected Profit (\$)	-2850			4140			-615		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	70	0	0	0	70	70	0	0
EV Agg Y1	Expected Profit (\$)	-			770			-1540		
	DA Bid Price (\$/MWh)	-			35			35		
	RT Offer Prices (\$/MWh)	-	-	-	0	0	70	70	0	0
EV Agg Y1	Expected Profit (\$)	-			3321.5			-1540		
	DA Bid Price (\$/MWh)	-			35			35		
	RT Offer Prices (\$/MWh)	-	-	-	0	0	70	70	0	0

Table C.2
The Results of Profit and Prices for Case 2

		Without EV			100,000 EVs			200,000 EVs		
Prices	DA Market Price (\$/MWh)	35			35			35		
	EV Tariff (\$/MWh)	-			35			35		
	RT Market Prices (\$/MWh)	70	22.5	27.5	25	27.5	46.25	20	30	47.5
Profits	Total Profit (\$)	69290			72455			72690		
	Total Profit of Firm 1 (\$)	25740			27575			27660		
	Total Profit of Firm 2 (\$)	43550			44880			45030		
	Total Profit of Firm 3 (\$)	-			-			-		
Wind UnitY1	Expected Profit (\$)	11170			8505			8210		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	0	0	0
Wind UnitY2	Expected Profit (\$)	6220			5180			5060		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	0	0	0
Nuclear UnitY2	Expected Profit (\$)	34500			34500			34500		
	DA Offer Price (\$/MWh)	0			0			0		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	0	0	0
Coal UnitY1	Expected Profit (\$)	13420			16500			16500		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	22.7	27.5	25	27.5	46.25	20	30	47.5
Oil UnitY2	Expected Profit (\$)	2830			4952.5			5070		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	22.5	27.7	25	28	46.25	20	30	47.5
Gas UnitY1	Expected Profit (\$)	1150						2400		
	DA Offer Price (\$/MWh)	35			35			34.96		
	RT Offer Prices (\$/MWh)	70	22.7	27.5	25	27.5	46.25	20	30	47.5
EV Agg Y1	Expected Profit (\$)	-			247.5			550		
	DA Bid Price (\$/MWh)	-			35			35		
	RT Offer Prices (\$/MWh)	-	-	-	25	27.5	46.25	20	30	47.5
EV Agg Y2	Expected Profit (\$)	-			247.5			400		
	DA Bid Price (\$/MWh)	-			35			35		
	RT Offer Prices (\$/MWh)	-	-	-	25	27.5	46.25	20	30	47.5

Table C.3
The Results of Profit and Prices for Case 3

		Without EV			100,000 EVs			200,000 EVs		
Prices	DA Market Price (\$/MWh)	35			35			35		
	EV Tariff (\$/MWh)	-			35			35		
	RT Market Prices (\$/MWh)	70	70	0	0	70	70	0	70	0
Profits	Total Profit (\$)	70550			72170			72170		
	Total Profit of Firm 1 (\$)	70550			72170			72170		
	Total Profit of Firm 2 (\$)	-			0			0		
	Total Profit of Firm 3 (\$)	-			-			-		
Wind Unit Y1	Expected Profit (\$)	12740			5740			9940		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	0	0	0
Wind Unit Y1	Expected Profit (\$)	7140			3640			6440		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	0	0	0
Nuclear Unit Y1	Expected Profit (\$)	34500			34500			34500		
	DA Offer Price (\$/MWh)	0			0			0		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	0	0	0
Coal Unit Y1	Expected Profit (\$)	16500			17550			16500		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	70	0	0	70	70	0	70	0
Oil Unit Y1	Expected Profit (\$)	2520			5500			5150		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	70	0	0	70	70	0	70	0
Gas Unit Y1	Expected Profit (\$)	-2850			5240			-360		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	70	0	0	70	70	0	70	0
EV Agg Y2	Expected Profit (\$)	-			0			0		
	DA Bid Price (\$/MWh)	-			35			35		
	RT Offer Prices (\$/MWh)	-	-	-	0	70	70	0	70	0
EV Agg Y2	Expected Profit (\$)	-			0			0		
	DA Bid Price (\$/MWh)	-			35			35		
	RT Offer Prices (\$/MWh)	-	-	-	0	70	70	0	70	0

Table C.4
The Results of Profit and Prices for Case 4

		Without EV			100,000 EVs			200,000 EVs		
Prices	DA Market Price (\$/MWh)	35			35			35		
	EV Tariff (\$/MWh)	-			35			35		
	RT Market Prices (\$/MWh)	70	70	70	70	70	70	70	70	70
Profits	Total Profit (\$)	65280			64790			67767.333		
	Total Profit of Firm 1 (\$)	14630			12880			12880		
	Total Profit of Firm 2 (\$)	50650			50650			52398		
	Total Profit of Firm 3 (\$)	-			1260			2489.333		
Wind Unit Y1	Expected Profit (\$)	8540			8540			8540		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	0	0	0
Wind Unit Y1	Expected Profit (\$)	6090			4340			4340		
	DA Offer Price (\$/MWh)	35			0			35		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	0	0	0
Nuclear Unit Y2	Expected Profit (\$)	34500			34500			34500		
	DA Offer Price (\$/MWh)	0			0			0		
	RT Offer Prices (\$/MWh)	0	0	0	0	0	0	0	0	0
Coal Unit Y2	Expected Profit (\$)	16500			16500			16500		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	70	70	70	70	70	70	70	70
Oil Unit Y2	Expected Profit (\$)	250			250			250		
	DA Offer Price (\$/MWh)	35			35			35		
	RT Offer Prices (\$/MWh)	70	70	70	70	70	70	78.57	78.57	70
Gas Unit Y2	Expected Profit (\$)	-600			-600			1148		
	DA Offer Price (\$/MWh)	35			35			34.96		
	RT Offer Prices (\$/MWh)	70	70	70	70	70	70	73.81	70	77.61
EV Agg Y3	Expected Profit (\$)	-			490			1126.667		
	DA Bid Price (\$/MWh)	-			35			35		
	RT Offer Prices (\$/MWh)	-	-	-	70	70	70	70	70	70
EV Agg Y3	Expected Profit (\$)	-			770			1362.667		
	DA Bid Price (\$/MWh)	-			35			35		
	RT Offer Prices (\$/MWh)	-	-	-	70	70	70	70	70	70

Table C.5
The Results of Demand and Generation Dispatch for Case 1

	(MW)	Without EV			100,000 EVs			200,000 EVs		
	Demand Curtailment of LSE	0	0	0	0	0	0	0	0	0
	Total Wind Power Deviation	+250	-40	-250	+250	-40	-250	+250	-40	-250
Wind Unit Y1	DA Power	300			300			300		
	Wind Power Deviation	+200	-20	-150	+200	-20	-150	+200	-20	-150
	Wind Power Curtailment	0	0	0	0	0	0	0	0	0
Wind Unit Y1	DA Power	200			200			200		
	Wind Power Deviation	+50	-20	-100	+50	-20	-100	+50	-20	-100
	Wind Power Curtailment	0	0	0	0	0	0	0	0	0
Nuclear Unit Y1	DA Power	1500			1500			1500		
	Regulation Up/Down	0	0	0	0	0	0	0	0	0
	RT Power Output	1500	1500	1500	1500	1500	1500	1500	1500	1500
Coal Unit Y1	DA Power	1100			1045.5			1100		
	Regulation Up/Down	0	0	0	54.5	54.5	54.5	0	0	0
	RT Power Output	1100	1100	1100	1100	1100	1100	1100	1100	1100
Oil Unit Y1	DA Power	250			250			500		
	Regulation Up/Down	-100	190	250	250	250	250	-50	0	0
	RT Power Output	150	440	500	500	500	500	500	450	500
Gas Unit Y1	DA Power	150			200			365		
	Regulation Up/Down	-150	-150	0	-190	100	200	-200	35	35
	RT Power Output	0	0	150	10	300	400	165	400	400
EV Agg Y1	POP	-			-364.5			-729		
	Regulation Up/Down	-	-	-	0	0	+55	0	5	105
	RT Power Output	-	-	-	-364.5	-364.5	-309.5	-729	-724	-624
EV Agg Y1	POP	-			0			-729		
	Regulation Up/Down	-	-	-	-364.5	-364.5	-309.5	0	0	110
	RT Power Output	-	-	-	-364.5	-364.5	-309.5	-729	-729	-619

Table C.6
The Results of Demand and Generation Dispatch for Case 2

		(MW)	Without EV			100,000 EVs			200,000 EVs		
		Demand Curtailment of LSE	0	0	0	0	0	0	0	0	0
		Total Wind Power Deviation	+250	-40	-250	+250	-40	-250	+250	-40	-250
Wind UnitY1	DA Power		0			300			300		
	Wind Power Deviation		+200	-20	-150	+200	-20	-150	+200	-20	-150
	Wind Power Curtailment		0	0	0	0	0	0	0	0	0
Wind UnitY2	DA Power		0			200			200		
	Wind Power Deviation		+50	-20	-100	+50	-20	-100	+50	-20	-100
	Wind Power Curtailment		0	0	0	0	0	0	0	0	0
Nuclear UnitY2	DA Power		1500			1500			1500		
	Regulation Up/Down		0	0	0	0	0	0	0	0	0
	RT Power Output		1500	1500	1500	1500	1500	1500	1500	1500	1500
Coal UnitY1	DA Power		1100			1100			1060		
	Regulation Up/Down		-300	-80	0	0	0	0	0	+40	+40
	RT Power Output		800	1020	1100	1100	1100	1100	1060	1100	1100
Oil UnitY2	DA Power		500			455			480		
	Regulation Up/Down		-250	-180	-100	-50	+20	+45	-50	+20	+20
	RT Power Output		250	320	400	405	475	500	420	500	500
Gas UnitY1	DA Power		400			305			400		
	Regulation Up/Down		-200	-200	-150	-200	+20	+95	-200	-20	0
	RT Power Output		200	200	250	205	325	400	200	380	400
EV AggY1	POP		-			-364.5			-729		
	Regulation Up/Down		-	-	-	0	0	+55	0	0	+110
	RT Power Output		-	-	-	-364.5	-364.5	-309.5	-729	-729	-629
EV AggY2	POP		-			-364.5			-729		
	Regulation Up/Down		-	-	-	0	0	+55	0	0	+80
	RT Power Output		-	-	-	364.5	364.5	-309.5	-729	-729	-649

Table C.7
The Results of Demand and Generation Dispatch for Case 3

	(MW)	Without EV			100,000 EVs			200,000 EVs		
	Demand Curtailment of LSE	0	0	0	0	0	0	0	0	0
	Total Wind Power Deviation	+250	-40	-250	+250	-40	-250	+250	-40	-250
Wind Unit Y1	DA Power	300			300			300		
	Wind Power Deviation	+200	-20	-150	+200	-20	-150	+200	-20	-150
	Wind Power Curtailment	0	0	0	0	0	0	0	0	0
Wind Unit Y1	DA Power	200			200			200		
	Wind Power Deviation	+50	-20	-100	+50	-20	-100	+50	-20	-100
	Wind Power Curtailment	0	0	0	0	0	0	0	0	0
Nuclear Unit Y1	DA Power	1500			1500			1500		
	Regulation Up/Down	0	0	0	0	0	0	0	0	0
	RT Power Output	1500	1500	1500	1500	1500	1500	1500	1500	1500
Coal Unit Y1	DA Power	1100			1050			1100		
	Regulation Up/Down	0	0	0	50	50	50	0	0	0
	RT Power Output	1100	1100	1100	1100	1100	1100	1100	1100	1100
Oil Unit Y1	DA Power	250			500			450		
	Regulation Up/Down	-100	190	250	-100	0	0	-50	50	50
	RT Power Output	150	440	500	400	500	500	400	500	500
Gas Unit Y1	DA Power	150			200			200		
	Regulation Up/Down	-150	-150	0	-200	-10	200	-200	-10	200
	RT Power Output	0	0	150	0	190	400	0	400	400
EV Agg Y2	POP	-			-364.5			-729		
	Regulation Up/Down	-	-	-	0	0	0	0	0	0
	RT Power Output	-	-	-	-364.5	-364.5	-364.5	-729	-729	-729
EV Agg Y2	POP	-			-364.5			-729		
	Regulation Up/Down	-	-	-	0	0	0	0	0	0
	RT Power Output	-	-	-	-364.5	-364.5	-364.5	-729	-729	-729

Table C.8
The Results of Demand and Generation Dispatch for Case 4

		(MW)	Without EV			100,000 EVs			200,000 EVs		
		Demand Curtailment of LSE	150	40	150	163.8	36.36	181.8	34.1	9.52	47.16
		Total Wind Power Deviation	+250	+10	-200	+250	-40	-250	+250	-40	-250
Wind UnitY1	DA Power	300			300			300			
	Wind Power Deviation	+200	-20	-150	+200	-20	-150	+200	-20	-150	
	Wind Power Curtailment	0	0	0	0	0	0	0	0	0	
Wind UnitY1	DA Power	150			200			200			
	Wind Power Deviation	+100	+30	-50	+50	-20	-100	+50	-20	-100	
	Wind Power Curtailment	0	0	0	0	0	0	0	0	0	
Nuclear UnitY2	DA Power	1500			1500			1500			
	Regulation Up/Down	0	0	0	0	0	0	0	0	0	
	RT Power Output	1500	1500	1500	1500	1500	1500	1500	1500	1500	
Coal UnitY2	DA Power	1100			1100			1100			
	Regulation Up/Down	0	0	0	0	0	0	0	0	0	
	RT Power Output	1100	1100	1100	1100	1100	1100	1100	1100	1100	
Oil UnitY2	DA Power	250			250			250			
	Regulation Up/Down	-250	-250	250	-250	-250	250	-250	-250	+250	
	RT Power Output	0	0	500	0	0	500	0	0	500	
Gas UnitY2	DA Power	200			200			108			
	Regulation Up/Down	-200	200	-200	-200	200	-200	-108	+200	-108	
	RT Power Output	0	400	0	0	400	0	0	308	0	
EV Agg Y3	POP	-			-364.5			-729			
	Regulation Up/Down	-	-	-	36.2	16.81	0	0	80.48	0	
	RT Power Output	-	-	-	-328.3	-348.3	-364.5	-729	-648.5	-729	
EV Agg Y3	POP	-			-364.5			-729			
	Regulation Up/Down	-	-	-	0	36.83	18.2	73.9	0	60.84	
	RT Power Output	-	-	-	-364.5	-327.6	-346.3	-655.1	-729	-668.1	

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